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JIP Terms and Acronyms

General

BOP – Blow Out Preventer
DH - Direct Hydraulic
DSV – Diving Support Vessel
DTTAS – Dry Tree Tie-back Alternative Study
HPU – High Pressure Unit
LWRP – Lower Workover Riser Package
MSV – Multi-service Support Vessel
MTTR – Mean Time To Repair
PLEM – Pipeline End Manifold
WOCS – Workover Control System

Completion

CI – Chemical Injection
CID – Chemical Injection Downhole
CV – Check Valve
DHPT – Down Hole Pressure / Temp Transducer
SCSSV – Surface Controlled Subsurface Safety Valve
TH – Tubing Hanger

Tubing Head

THL – Tubing Head Connector Lock
THU – Tubing Head Connector Unlock
THSU – Tubing Head Secondary Unlock
THT – Tubing Head/Wellhead Test
THTV – Tubing Head Test Valve

Tree Cap

ACV – Annulus Cap Valve
PCV – Production Cap Valve
TCL – Tree Cap Lock
TCU – Tree Cap Unlock
TCSU – Tree Cap Secondary Unlock
TCT – Tree Cap Test

Manifold

FIVA – Flowline Isolation Valve – Header A
FIVB – Flowline Isolation Valve – Header B
MPV – Manifold Pigging Valve
PIVA – Pigging loop Isolation Valve – Header A
PIVB – Pigging loop Isolation Valve – Header B
WIVA – Well Isolation Valve – Header A
WIVB – Well Isolation Valve – Header B

Tree
AAV – Annulus Access Valve
AIV – Annulus Isolation Valve
AMV – Annulus Master Valve
ASV – Annulus Swab Valve
AVV – Annulus Vent Valve
AWV – Annulus Wing Valve
AXV – Annulus Crossover Valve
CI – Chemical Injection
CID – Chemical Injection Downhole
CIT – Chemical Injection Tree
CV – Check Valve
FCL - Flowline Connector Lock
FCU - Flowline Connector Unlock
FCSU – Flowline Connector Secondary Unlock
FIV – Flowline Isolation Valve
HPH – High Pressure Hydraulics
LMV – Lower Master Valve
LPH – Low Pressure Hydraulics
PCV – Production Choke Valves
PDPG - Permanent Downhole Pressure Gauge
PIV – Production Isolation Valve
PMV – Production Master Valve
PSV – Production Swab Valve
P/T – Pressure Temperature Transducer
PWV – Production Wing Valve
SCSSV – Surface Controlled Subsurface Safety Valve
TCT – Tree Connector Test
TH – Tubing Hanger
UMV – Upper Master Valve
VPI – Variable Position Indicator
XOV –Cross Over Valve

Workover Riser
EDT – Emergency Disconnect Test
EDU – Emergency Disconnect Unlock
EDL – Emergency Disconnect Lock
AIV – Annulus Isolation Valve
PIV – Production Isolation Valve
XOV – Cross Over Valve
TRTT– Tree Running Tool Test
TRTU – Tree Running Tool Unlock
TRTL – Tree Running Tool Lock

Surface Tree
SAMV – Surface Annulus Master Valve
SAWV – Surface Annulus Wing Valve
SASV – Surface Annulus Swab Valve
SPMV – Surface Production Master Valve
SPWV - Surface Production Wing Valve
SPSV - Surface Production Swab Valve

EXECUTIVE SUMMARY

The purpose of this Joint Industry Project (JIP) is to develop and demonstrate a probabilistic procedure for assessing the lifetime risk and reliability adjusted cost of subsea production systems with respect to safety, environmental and operational parameters. The results of this Subsea JIP have been combined with the previous Dry Tree Tie-back Alternatives Study, DTTAS, to provide a combined Spreadsheet Tool for assessing the lifetime risk and reliability adjusted cost for either / both systems.

I. Background

There are a number of different ways of developing oil fields in deepwater. Dry Tree Tieback Concepts ("Dry") require a platform to support the permanently attached production/intervention risers, but provide the efficiency and the convenience of direct well access for remedial activities. Subsea Tieback Concepts ("Wet") provide greater flexibility in utilization of existing infrastructure, well location and development schedules, but require more challenging and costly well interventions/workovers. The fundamental question is whether the higher OPEX of a subsea system is justified for the lower CAPEX as compared with a dry tree tieback system. Either system can perform the functional requirement, and in many cases a hybrid solution is the way to go. The challenge is to identify and quantify the advantages and disadvantages for the various concepts so that a decision can me made taking all economic factors into account.

In 1998 a methodology was developed by the Joint Industry Project (JIP) "Dry Tree Tieback Alternatives", sponsored by 12 oil companies and the US Minerals Management Service (MMS), to estimate CAPEX, OPEX and RISKEX (the probability of blowout during field life multiplied by the cost of a blowout) for various well riser alternatives. The methodology was demonstrated by comparing dual casing riser ("3 pipe"), single casing riser ("2 pipe") and tubing riser ("1 pipe") alternatives for SPARs and TLPs in 4000 and 6000 feet of water depth. The methodology can be used to select the well riser system with the lowest total cost (CAPEX, OPEX and RISKEX) taking site specific conditions into account. The objective was to identify significant differences between the three riser tieback concepts, hence the methodology did not consider any cost associated with "Production Downtime" or "Deferral of Revenues" caused by incidents that do not result in an uncontrolled release to the environment (e.g. downtime due to repair of leaking tubing joint). The DTTAS did not included cost such as TLP or SPAR platform, processing facilities, drilling and field operations. These costs were essentially the same for all the riser alternatives.

The methodology developed in this "Lifetime Cost of Subsea Production Systems JIP" is patterned after the methodology that has been developed and demonstrated in the "Dry Tree Tieback Alternatives JIP" and previous studies, /1, 2, 3, 4, 5/. In some respects this is an

[1] Alan H. Woodyard, "Risk Analysis of Well Completion Systems," Journal of Petroleum Technology, April 1982, pp. 713-720.

[2] Joint Industry Project, "Risk Assessment for Dry Tree Tieback Alternatives," Phase 2 Study Final Report, March 1998.

[3] R. Goldsmith, R. Eriksen, F. J. Deegan, "Lifetime Risk-Adjusted Cost Comparison for Deepwater Well Riser Systems" presented at OTC in Houston, May 1999 (OTC 10976).

[4] Remi Eriksen and Riley Goldsmith, "Selecting Deepwater Drilling and Production Riser Systems with Lowest Total Field-Life Cost" presented at Deep Oil Technology Conference, Stavanger, Norway, October 1999.

extension of the "Dry Tree Tieback Alternatives JIP". Most of the project team members from the "Dry Tree Tieback Alternatives JIP" have participated in the project work in this JIP.

II. Scope of Work

This "Lifetime Cost of Subsea Production Systems JIP" broadens the scope of the previous Dry Tree Tieback Study to include conventional and horizontal tree subsea well systems in addition to SPAR and TLP dry tree well systems. In addition, Reliability-Availability-Maintainability expenditures, RAMEX, are included in this study. The methodology developed in this study is especially useful for comparing alternative field development scenarios. The following cost elements are considered for dry tree and subsea systems:

- CAPEX, capital costs of materials and installation of the wells and systems. Materials includes dry tree risers with associated equipment such as tensioners for TLP's, air can buoyancy for SPAR's and surface trees, subsea systems such as subsea trees, pipelines, pipeline end manifolds, jumpers, umbilicals and controls systems. Installation costs includes vessel spread cost multiplied by the estimated installation time and for rental or purchase of installation tools and equipment.
- OPEX, operating costs to perform "planned" zonal recompletions. OPEX for these planned recompletions is intervention vessel (MODU) spread cost multiplied by the estimated recompletion time for each zonal recompletion. The number and timing of planned recompletions are uniquely dependent on the site-specific reservoir characteristics and operator's field development plan. This study has developed a methodology that permits the user to use individual well reserves, initial production rates and production decline rates to "plan" a well recompletion schedule and a total field production profile.
- RISKEX, risk costs associated with loss of well control (blowouts) during installation, normal production operations and during recompletions. Risk cost is calculated as the probability of uncontrolled leaks times assumed consequences of the uncontrolled leaks.
- RAMEX, reliability-availability-maintainability costs associated with well or system component failures. Both the "loss of production" costs and "failed component repair/replacement" costs are determined.

Cost elements that are beyond the scope of this study are:

- SPAR or TLP platform facilities materials and installation costs (platform, processing facilities, export risers and pipelines, drilling/workover rig, etc.).
- Drilling costs.
- Downhole completion equipment costs (packer , tubing, SCSSV, etc.).
- Field operations costs such as platform maintenance, downhole treatment chemicals, production operating personnel and boats and helicopters.

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5 Remi Eriksen and Brian Saucier, "Selecting Cost-Effective and Safe Deepwater Completion Tieback Alternatives," presented at OTC in Houston, May 2000 (OTC 12167).

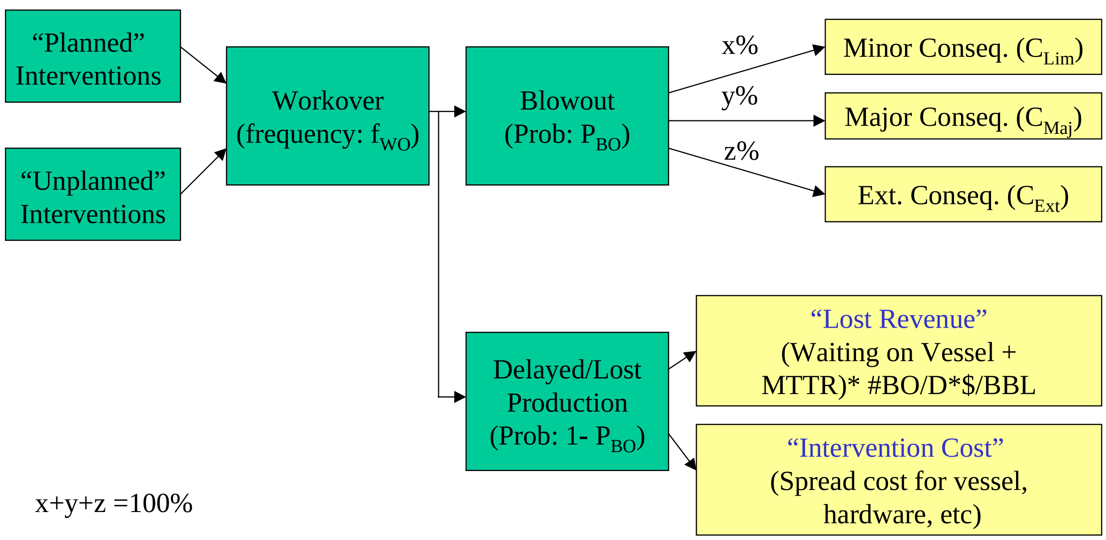
Many of these cost elements are the same for alternative field development scenarios. However, comparison of subsea production systems with dry tree wells must include TLP or Spar platform costs with the dry tree alternatives. Dry tree drilling costs may be greater because directional wells are required as compared to vertical subsea wells.

The methodology is developed to permit predictions of lifetime cost for a field development based on statistical and judgmental reliability data and assumed system parameters.

- The system is broken down to a level where some experience data is available and where it is possible to evaluate failure modes and their corresponding effect on system level.
- The quality of the input data (reliability of completion string components, sand control system failures, subsea equipment, risers, individual well production profiles, rig availability time, rig spread costs, etc.) is independently evaluated to minimize bias.
- The methodology and spreadsheet tool "model" show the sensitivity to changes in specific input data that is not readily apparent otherwise.
- This model is especially useful to determine which parameters most influence field development cost. The quality of data for these parameters can then be scrutinized to achieve the maximum practical quality. Likewise, attempting to improve the quality of data that are of minor importance does not waste time.
- Sensitivity analyses can determine the financial incentive for improving reliabilities of components.

The RISKEX and RAMEX calculation approach is illustrated in Figure 1.

Figure 1: RISKEX and RAMEX Calculation Principles



III. Deliverables

The deliverables for this project are as follows:

- Ranked database of subsea component reliabilities.
- Subsea system functional specification.
- Suite of well intervention operating procedures.
- Initial completions.
- Re-completions and workovers.
- Subsea component repairs / replacements (tree, flowline, umbilical, control pod, etc.).
- Suite of subsea system component CAPEX.
- Spreadsheet model to calculate well related total costs: capital expenditures (CAPEX), operating expenditures (OPEX), risk expenditures (RISKEX) and reliability-availability-maintainability expenditures (RAMEX).

IV. Subsea System

A 6-well satellite clustered subsea system was defined to provide a basis for analysis and testing the model. The subsea system includes hydraulic and electrical umbilicals and pipeline connecting the subsea system to a remote host platform. Flowline jumpers connect the pipeline end manifolds to a 6-well manifold and well jumpers connect the manifold to individual wells that are clustered around the manifold. Hydraulic and electrical flying leads connect the hydraulic and electrical termination units to individual wells.

Although the base case for the model testing was the 6-well subsea system with 35 mile tieback distance, the model evaluates subsea systems from a few as 2 or 3 wells to as many as 10 or 12 subsea wells at various tieback distances.

Specific well designs and operating procedures are developed for both conventional subsea tree and horizontal subsea tree systems. There are significant differences between these systems, especially in the operational procedures repairing well system component failures.

Failure Mode Effects Analysis, FMEA, was performed to identify and document the failures and potential consequences for the 6-well satellite clustered subsea system. This FMEA provided the basis for developing the fault tree to calculate RISKEX and RAMEX.

Operating procedures are developed for initial installation of completion systems in pre-drilled wells, planned workovers to new intervals as zones deplete, and unplanned workovers to repair and/or replace failed components such as a sand control system or a leaking tubing string. These operating procedures are used to calculate capital costs, CAPEX, the cost of planned interventions, OPEX, costs to repair completions component failures, RAMEX, and individual steps of the operating procedures define changes in the well control barriers that provide the basis for risk costs, RISKEX.

CAPEX is calculated as the total of well system materials and installation costs. The dry tree alternatives materials costs are derived from the Phase I Dry Tree Alternative Study and include riser related costs for:

- TLP or Spar[6]
- dual casing risers, single casing risers and tubing riser materials
- 6 well system or 12 well system
- 4000-foot water depth ore 6000 foot water depth.

CAPEX for the subsea well system includes:

- Pipelines between the subsea wells and host facility,
- pipeline end manifolds, PLEM,
- subsea production manifolds,
- jumpers to connect the pipeline and manifold,
- hydraulic and electrical umbilicals,
- well jumpers, and
- conventional subsea trees or horizontal subsea trees.

Installation costs that are included in the CAPEX include the user defined vessel(s) spread costs multiplied by the vessel(s) operating time for initial well interventions and initial subsea system installations.

V. Base Case Results

The methodology and spreadsheet program developed by this Subsea JIP provides a means to quantify the CAPEX, OPEX, RISKEX and RAMEX factors that determine the differences in these well systems.

Several Base Case calculations were run to compare the lifecycle costs of the alternative well systems. The Base Case input data are summarized in Table 1.

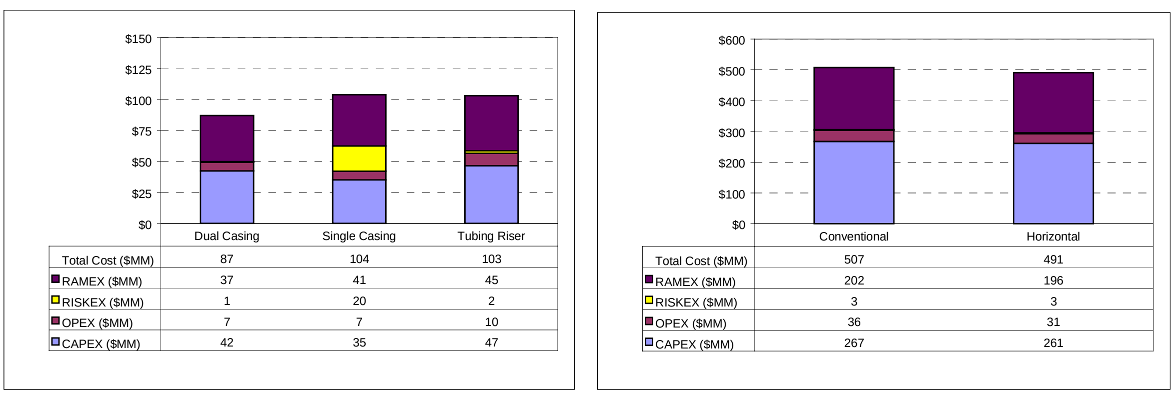
The lifecycle costs (CAPEX, OPEX, RISKEX and RAMEX) for the different well system alternatives are shown for one of the case examples in Figure 2. **Platform and facilities costs must be included with these costs to determine the most economical well system and field development plan.**

[6] CAPEX includes only well system costs such as riser components and subsea facilities. Costs for the TLP or Spar platform, processing facilities, drilling facilities, drilling of wells and downhole completion tools are not included.

Table 1: Case Study Input Data

	Case 1	Case 2a	Case 2b
Field Life (years)	10	10	10
Zone depth (feet BLM)	10,000	10,000	10,000
Pipeline size (in) - for subsea equipment	12	12	12
Pipeline length (mi) – for subsea equipment	35	35	35
Infield extension (mi) – for subsea equipment	5	5	5
Facilities processing limit (MBOPD)	No limit	No limit	No limit
Oil op. margin in year produced ($/bbl)	8	8	8
Discount rate for NPV calculations (%)	15	15	15
	6 wells 12 wells		
number of frac pack wells	3 6	3	3
number of horizontal wells	3 6	3	3
number of planned uphole frac packs	2 4	4	1
number of planned sidetrack frac packs	2 4	4	1
number of planned sidetrack horizontals	2 5	4	1
number of unplanned tree replacements	2 4	1	3.5
number of unplanned downhole repairs	2.5 5	5	1.5
number of unplanned sand control repairs	5 10	8	3
Limited uncontrolled release cost ($ / BOPD)	$1,700	$1,700	$1,700
Major uncontrolled release cost ($ / BOPD)	$35,000	$35,000	$35,000
Extreme uncontrolled release cost ($ / BOPD)	$250,000	$250,000	$250,000
X-factor	0.8	0.8	0.8
SCSSV location (feet below mudline)	2000	2000	2000
Common cause factor for DC system	0.003	0.003	0.003

Figure 2: Completion Alternatives Lifecycle Cost ($MM NPV)– Case 1a, 6 wells, 4000 ft



	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	87	104	103
RAMEX ($MM)	37	41	45
RISKEX ($MM)	1	20	2
OPEX ($MM)	7	7	10
CAPEX ($MM)	42	35	47

	Conventional	Horizontal
Total Cost ($MM)	507	491
RAMEX ($MM)	202	196
RISKEX ($MM)	3	3
OPEX ($MM)	36	31
CAPEX ($MM)	267	261

Subsea wells can be located at locations that are remote to a drilling or production facility whereas dry tree wells require an expensive platform. However, subsea wells generally experience lower operating efficiency "Uptime," and repair costs and lost production greater than dry tree well systems. Figure 2 shows a typical RAMEX case example where the dry tree wells have about 98% uptime as compared to about 90% uptime for subsea wells. Repair costs for the dry tree wells is in the range of 12 to 15 million dollars as compared to 65 to 69 million dollars for subsea wells. The production lost cost is 25 to 30 million for the dry tree wells as compared to about 132 million for the subsea wells.

Table 2: Completion Alternatives RAMEX Results – Case 1a, 6 wells, 4000 ft

	Dual Casing	**Single Casing**	**Tubing Riser**	**Conventional**	**Horizontal**
% Uptime	98.0 %	97.8 %	97.8 %	89.6 %	89.6 %
Repair Cost ($MM)	11.4	12.0	15.7	69.4	64.1
PRODUCTION LOST ($MM)	25.6	29.1	28.9	132.3	131.9
Total RAMEX ($MM)	**37.0**	**41.1**	**44.6**	**201.7**	**196.0**

A case example is also shown in the Results Section of this report to demonstrate the differences in conventional and horizontal subsea tree systems. Horizontal subsea tree system permits workover operations without removing the subsea trees. This system is most economical if numerous workovers are required for recompletions to new zones.

Conventional subsea trees can be replaced more easily than horizontal trees in the event of the failure of a tree valve or actuator. Conventional subsea trees can be replaced without pulling the completions string; horizontal subsea trees require the completion string to be pulled prior to pulling the tree. Therefore, the most economical type of tree is influenced by the reliability of the tree components such as valves, valve actuators, connectors, etc.

VI. Acknowledgements

The Joint Industry Project (JIP) team for the “Lifetime Cost Of Subsea Production Systems” project wishes to acknowledge the participation and assistance from the representatives from the following companies:

- Arco Exploration and Production Technology (now BP Amoco)
- BHP Petroleum Americas, Inc.
- Chevron Petroleum Technology Co.
- Conoco Inc.
- Elf Exploration Inc.
- Minerals and Management Service

Their assistance, guidance and expert knowledge contributed greatly to the achievement of the goals for the project.

1 INTRODUCTION

1.1 Purpose

The purpose of this Joint Industry Project (JIP) is to develop and demonstrate a probabilistic procedure for assessing the lifetime risk and reliability adjusted cost of subsea systems with respect to safety, environmental and operational parameters. The results of this Subsea JIP have been combined with the previous Dry Tree Tie-back Alternatives Study, DTTAS, to provide a combined Spreadsheet Tool for assessing the lifetime risk and reliability adjusted cost for either / both systems.

1.2 Background

The methodology used in this study is patterned after the methodology that has been developed and demonstrated in previous studies /1, 2, 3, 4, 5/. In some respects this "Lifetime Cost of Subsea Production Systems" Joint Industry Project is an extension of the Dry Tree Tie-back Alternative Study, DTTAS. Most of the project team members from the DTTAS have also participated in this subsea study. The DTTAS Phase I study estimated Capital Expenditures (CAPEX), and Operating Expenditures (OPEX), for three different dry tree riser configurations for both Tension Leg Platforms (TLPs) and Spar Platform Buoy (SPAR) facilities in the deepwater Gulf of Mexico. The Phase II study extended the analysis to include a method of determining a risk cost for these three riser alternatives.

Phase I of the DTTAS developed a set of reservoir specifications typical for Gulf of Mexico reservoirs. CAPEX and OPEX curves were calculated for a range of variables that included:

- TLP and SPAR platforms,
- 6 and 12 well systems,
- dual casing, single casing and a tubing riser systems,
- 2000, 4000 and 6000 feet water depths,
- 3 ½ inch and 5 ½ inch tubing completions.

The Phase II of the DTTAS utilized the Phase I design basis and extended the comparison to include RISKEX, the potential cost associated with losing well control (blowout) for these alternative systems. The methodology to determine RISKEX involves the calculation of total well system reliability based on individual completion component reliabilities and the steps of the installation, production and workover operations.

1. Alan H. Woodyard, "Risk Analysis of Well Completion Systems," Journal of Petroleum Technology, April 1982, pp. 713-720.
2. Joint Industry Project, "Risk Assessment for Dry Tree Tieback Alternatives," Phase 2 Study Final Report, March 1998.
3. R. Goldsmith, R. Eriksen, F. J. Deegan, "Lifetime Risk-Adjusted Cost Comparison for Deepwater Well Riser Systems" presented at OTC in Houston, May 1999 (OTC 10976).
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5. Remi Eriksen and Brian Saucier, "Selecting Cost-Effective and Safe Deepwater Completion Tieback Alternatives," presented at OTC in Houston, May 2000 (OTC 12167).

Individual completion components were identified and ranked according to sealing mechanisms, installation difficulty and operating conditions to estimate completion component reliabilities where statistical data were unavailable or sparse. Fault Trees were developed to calculate the lifetime system probability of an uncontrolled leak to the environment based on individual completion component reliabilities for each alternative well system and leak size. Several hundred fault tree calculations were carried out to estimate probabilities of an uncontrolled leak to the environment (limited, major and extreme) during the production mode and each step of the well intervention operations. A spreadsheet program was developed to facilitate the RISKEX calculation.

The leak frequencies predicted by the system reliability models developed by this JIP are very close to industry statistical blowout frequency data. This close agreement between prediction and observations strongly supports the validity of the individual completion component reliability data set that was developed in the DTTAS.

1.3 Scope

This "Lifetime Cost of Subsea Production Systems" study broadens the scope of the previous Dry Tree Tie-back Study to include conventional and horizontal tree subsea well systems as well as SPAR and TLP dry tree well systems. In addition, Reliability-Availability-Maintainability Expenditures, RAMEX, are included. The following cost elements are considered for dry tree and subsea systems:

- CAPEX, capital expenditures related to materials and installation of the wells and systems. Materials includes dry tree risers with associated equipment such as tensioners for TLP's, air can buoyancy for SPAR's and surface trees, subsea systems such as subsea trees, pipelines, pipeline end manifolds, jumpers, umbilicals and controls systems. Installation includes vessel spread cost multiplied by the estimated installation time and for rental or purchase of installation tools and equipment.
- OPEX, operating expenditures associated with the time to perform "planned" zonal recompletions. OPEX for these planned recompletions is MODU spread cost multiplied by the estimated recompletion time for each zonal recompletion. The number and timing of planned recompletions are uniquely dependent on the site-specific reservoir characteristics and operator's field development plan. This study has developed a methodology that permits the user to use individual well reserves, initial production rates and production decline rates to "plan" a well recompletion schedule and a total field production profile.
- RISKEX, the potential expenditures associated with loss of well control (blowouts) during installation, normal production operations and during recompletions. Risk cost is calculated as the probability of uncontrolled leaks times assumed consequences of the uncontrolled leaks.
- RAMEX, reliability-availability-maintainability costs associated with well or system component failures. Both the "loss of production" costs and "failed component repair/replacement" costs are determined.

Cost elements that are beyond the scope of this study are:

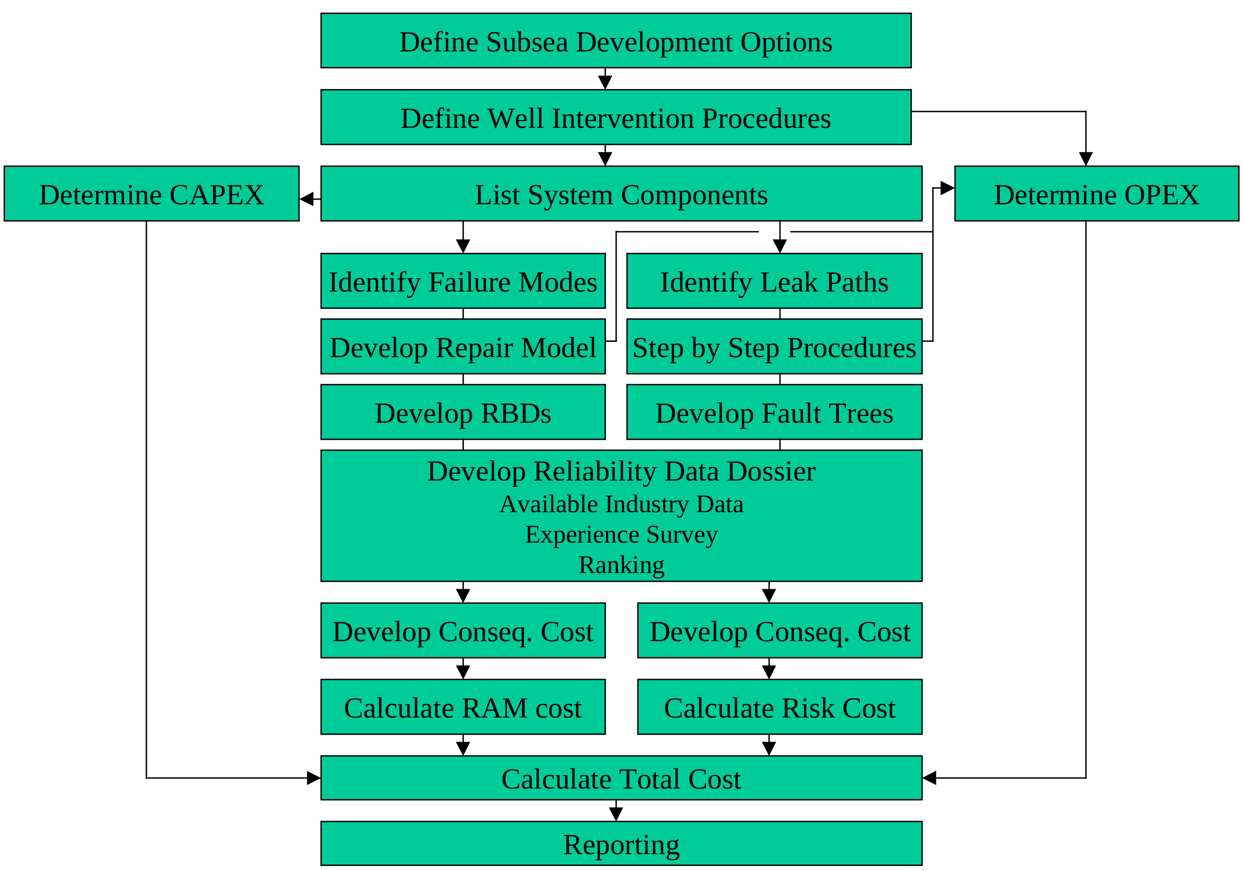
- SPAR or TLP platform facilities materials and installation costs (platform, processing facilities, export risers and pipelines, drilling/workover rig, etc.),
- Drilling costs,
- Downhole completion equipment costs,
- Field operations costs such as platform maintenance, downhole treatment chemicals, production operating personnel, and boats and helicopters.

Many of these cost elements are the same for alternative field development scenarios. However, comparison of subsea production systems with dry tree wells must include TLP or Spar platform costs with the dry tree alternatives. Dry tree drilling costs may be greater because directional wells are required as compared to vertical subsea wells.

1.4 Methodology

The project tasks and work flow are illustrated in Figure 1.1.

Figure 1.1: Project Tasks and Work Flow



1.5 Deliverables

The deliverables for this project are as follows:

- Database of subsea component reliabilities.
- Subsea system functional specification.
- Suite of well intervention operating procedures.
  - Initial completions
  - Re-completions and workovers
  - Subsea component repairs / replacements (tree, flowline, umbilical, control pod, etc.)
- Suite of subsea system component CAPEX.
- Spreadsheet model to calculate well related total costs: capital expenditures (CAPEX), operating expenditures (OPEX), risk expenditures (RISKEX) and reliability-availability-maintainability expenditures (RAMEX).

The data sources used consist of both participant surveys and generic industry databanks as follows:

- Existing Dry Tree Riser Study (Downhole Components).
- SINTEF data.
- OREDA Data Handbook.
- WellMaster Database.
- Engineering judgement
- JIP participants survey forms.
- Ranking Techniques

1.6 Base Case Design

The base case design used for this subsea study includes the same down hole completion components and reservoir parameters that were used in the DTTAS. This base case design is used to demonstrate the methodology and to compare subsea with dry tree systems.

The subsea development will be offset 35 miles from the host facility. There will be two 12” flowlines for pigging purposes. Six wells will be controlled and monitored via a Electro-hydraulic Multiplexed Control system. In–field hydraulic and electrical umbilicals will be independently run from the host and terminated at the subsea end with a hydraulic distribution manifold (HDM) and electrical distribution manifold (EDM). ROV installable flying leads will provide the interconnection between the EDM and HDM to provide both electrical power and signal to each tree subsea control module and low/high pressure control supply and chemical supply.

The host facility will support the hydraulic power unit (HPU), chemical injection pumps and fluids storage, and surface master control station (MCS). The subsea MCS will be integrated into the host facility main shutdown systems. In the event of a subsea or other disruption, host process operations will trigger a shut-in of the subsea field.

The production controls system will control and monitor all sensors and provide a means of remotely operating all hydraulic tree valves, downhole SCSSV, downhole pressure and temperature (P/T) sensors and manifold crossover valves. Hydraulic pressure and electrical power and signal provide the means to communicate with each tree via the E/H mux control pod. The pod is a unit that can be recovered and replaced with lower cost intervention vessels in the event of failure or loss of control. Due to disruption of either the electrical or hydraulic system, the design of the valves is fail safe closed (FSC) allowing complete shut-in of the system.

Figure 1.2: Satellite Cluster

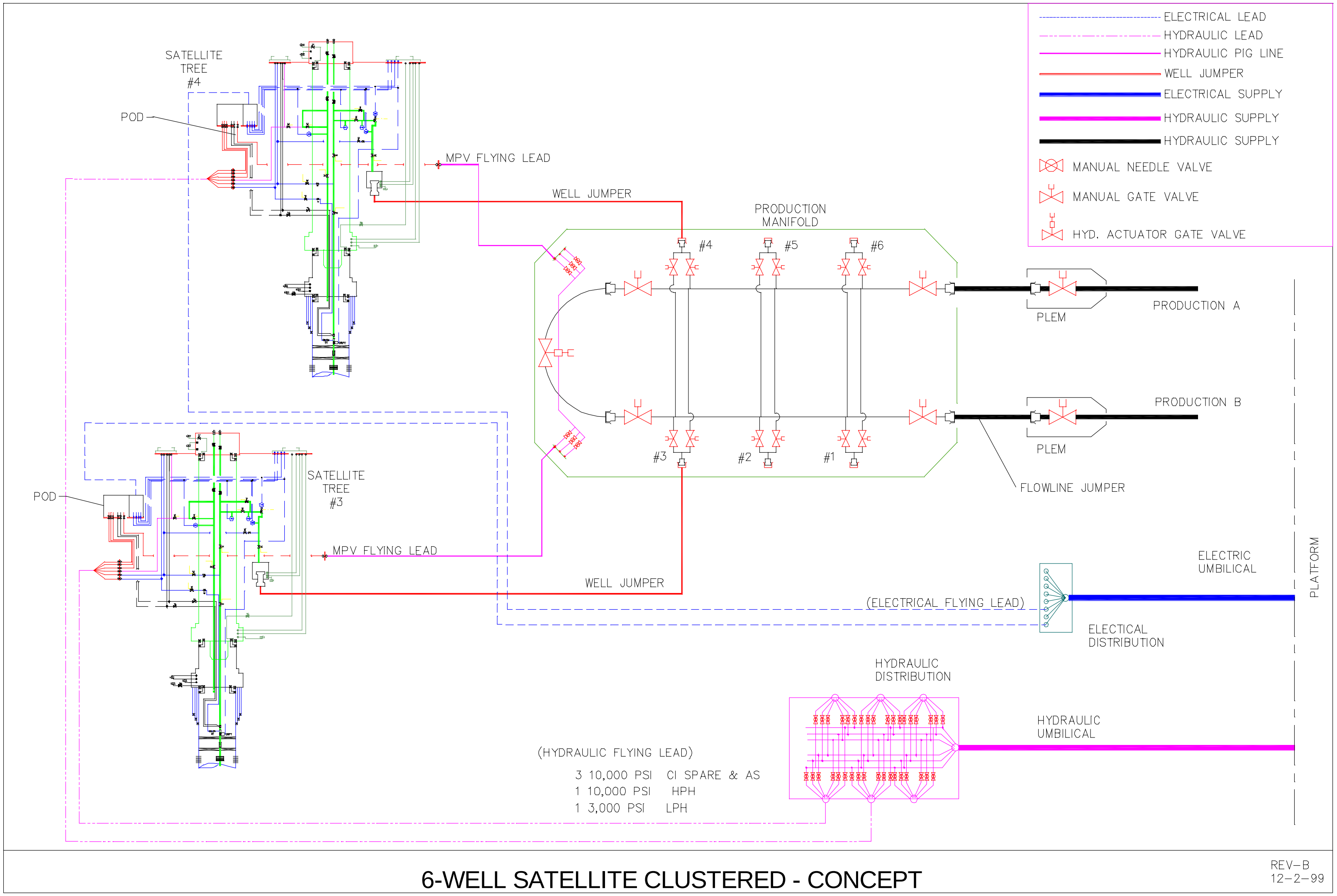


Table 1.1 is a short description of the overall system and reservoir parameters used in this study.

Table 1.1: Base Case Matrix

Description of Alternatives	Variations
Dry Tree Riser Tieback Configurations (A)	2
- Conventional Subsea Trees	1
- Horizontal Subsea Trees	1
Water Depths of 4000 ft and 6000 ft (B)	2
Production tubing size of 5.5 inch (C)	1
Wells per platform (D)	2
- 6 wells	1
- 12 wells	1
Intervention frequency (E)	2
- High # of downhole failures and low # of tree replacement failures	1
- Low # of downhole failures and high # of tree replacement failures	1
TOTAL CASES (AxBxCxDxE)	16

Table 1.2 is a short description of the overall system and reservoir parameters used in the DTTAS Phase II study.

Table 1.2: DTTAS Phase II Base Case Matrix

Description of Alternatives	Variations
TLP and Spar Buoy Development Scenarios (A)	2
- TLP	1
- SPAR	1
Dry Tree Riser Tieback Configurations (B)	3
- Dual Casing Risers (Similar to Shell Auger/Mars)	1
- Single Casing Risers (Similar to Conoco Jolliet/Heidrun)	1
- Tubing Riser Design (New Design, uninsulated case only)	1
Water Depths of 4000 ft and 6000 ft* (C)	2
Production tubing size of 5.5 inch* (D)	1
Wells per platform (E)	2
- 6 well 8 slot platform 30 MBOPD	1
- 12 well 16 slot platform 60 MBOPD	1
TOTAL CASES (AxBxCxDxE)	24

* The DTTAS Phase I also considered 2000 ft water depth, 3 ½ inch tubing and insulated tubing riser alternatives.

1.7 Reservoir Characteristics

The following reservoir characteristics have been used.

- The field life is 10 years.
- The reservoir depth is 10,000 feet below the sea floor for both water depths considered.

- The estimated true vertical depth of the wells is 14,000 - 16,000 ft. (Well intervention operations are based on reservoir depths of about 15,000 ft subsea.
- The flowing tubing pressure is 5,500 psi and the shut in tubing pressure is 6,500 psi. (10,000 psi working pressure equipment is required).
- All equipment is rated for 10,000 psi operating environment.
- The maximum flow rate from a well is 15 MBOPD.
- The number of well intervention operations expected in the field life is shown in Table 1.3.

Table 1.3: Expected Number of Planned Well Interventions

Initial Installations, Planned / Unplanned Workovers Based on 10 year Producing Life	Number Required	
	12 Well Case	6 Well Case
Initial Installation of Frac Pack Completion	6	3
Initial Installation of Horizontal Lateral Screen Completion	6	3
Pull Completion, Plug Lower Zone and Install Uphole Frac Pack Re-Completion	4	2
Pull Completion, Plug Lower Zone, Sidetrack and Re-complete with Frac Pack	4	2
Pull Completion, Plug Lower Zone Sidetrack and Re-Completion Horizontal Well	5	2

1.8 Environment

The base case subsea system is a six well development – assuming Gulf of Mexico environment and metocean conditions. Water depths considered are 4,000 and 6,000 feet.

Standard subsea wellheads have been assumed with conventional structure casing string(s) jetted into soft soil conditions.

2. METHODOLOGY

This section documents the methodology developed to estimate the lifecycle cost of subsea production systems.

2.1 Introduction

The economics of deepwater developments are different from shelf activities. Deepwater is characterized by high capital expenditures with relatively low operational expenditures and high sustainable production rates - hence high costs for production interruption.

Field development profitability is a function of many income and expense factors such as capital expenditures (CAPEX), operating expenditures (OPEX), production rate, product price and the frequency of completion component failures. Component failures reduce the field total production rate and increase intervention expenditures.

Until recently it was quite common for the decision making process used to evaluate deepwater ventures to focus on optimizing the balance between potential revenue, CAPEX and OPEX according to the equation:

$$Profit = Max\ (Revenue - CAPEX - OPEX) \qquad (2.1)$$

The shortcoming in this equation is that it does not take into account unscheduled and unplanned events that have the potential to destroy a facility, tarnish a company's reputation, pollute the environment, and/or shut down production for a long time. Major accidents, although highly unlikely, have the potential to put a facility out of business for 3, 6, 12 months or even render it totally useless.

When moving into deeper water, the economic penalty for delayed/lost production becomes greater. The uncertainty related to whether "unforeseen" events will occur is also increased as prototype and novel technology are introduced into an operating environment not encountered in shallow water platform design. Furthermore, subsea well system repairs and interventions also become more expensive and are associated with longer delays due to reduced availability and increased mobilization times for the required repair vessels. The alternative to a subsea system, a dry tree tieback concept provides the efficiency and the convenience of direct well access, but requires the surface host to support the weight of permanently attached production/intervention risers for which the load cost penalty and the likelihood of a riser leak increases with water depth.

The implications of disasters and business interruptions should be incorporated into business decision analyses that seek to evaluate the viability of alternative designs. These analyses introduce two more components to the economic "balance", namely, risk expenditures (RISKEX[1]) and reliability/availability/maintainability expenditures (RAMEX[2]). It takes a balanced, mature appraisal of the uncertainties and risks involved when considering front-end cost savings (CAPEX) that may have detrimental consequences on initial, intermediate and long-term revenue streams.

Inclusion of an "unforeseen" RISKEX and RAMEX element into equation (2.1) modifies the economic model to:

$$Profit = Max\ (Revenue - CAPEX - OPEX - RISKEX - RAMEX) \qquad (2.2)$$

The methodology is developed to permit predictions of lifetime cost for a field development based on statistical and judgmental reliability data and assumed system parameters. It might be asked "Why not simply estimate the lifetime cost for a field development rather than estimating all these input parameters?" The answers are:

- The system is broken down to a level where some experience data is available and where it is possible to evaluate failure modes and their corresponding effect on system level.
- The quality of the input data (reliability of completion string components, sand control system failures, subsea equipment, risers, individual well production profiles, rig availability time, rig spread costs, etc.) is independently evaluated to minimize bias.
- The methodology and spreadsheet tool "model" show the sensitivity to changes in specific input data that is not readily apparent otherwise.
- This model is especially useful to determine which parameters most influence field development cost. The quality of data for these parameters can then be scrutinized to achieve the maximum practical quality. Likewise, time is not wasted by attempting to improve the quality of data that are of minor importance.
- Sensitivity analyses can determine the financial incentive for improving reliabilities of components.

[1] RISK EXpenditures (RISKEX) are defined as the costs associated with the risks of a blowout. It is derived by estimating the frequency of the event and multiplying the frequency by the estimated cost (clean-up cost, outrage cost, asset damage cost and business interruption cost) for that event.

[2] Reliability/Availability/Maintainability EXxpenditures (RAMEX) are defined as the cost associated with lost revenues and interventions due to component failures.

2.2 System Boundaries

The systems that can be analyzed by using the proposed methodology are typical high-rate, deepwater well completion systems and cover both subsea well tieback and dry tree tieback concepts. A subsea well intervention has longer rig availability and mobilization time, is more sensitive to weather conditions, and is associated with higher day rates for the repair resource. However, all these parameters are part of the input data specified by the user.

The methodology includes:

Subsea: Downhole completion components, casing, wellhead equipment, subsea production trees, flowline jumpers, tie-in sleds, flowlines and risers (up to the boarding valve), subsea control module, control jumpers, subsea distribution units, umbilical termination assemblies, umbilicals, topside controls and chemical injection points.

Dry Tree: Downhole completion components, casing, wellhead equipment, risers, tensioners/air cans, surface production tree and manifold up to the 1st stage separation isolation valve.

For both concepts the well intervention equipment (risers, BOPs, controls, etc.) necessary to install and workover the completion equipment are included.

Examples of sand control systems considered by this project are frac-packs and horizontal laterals with gravel pack.

2.3 Life Cycle Cost Calculations

The CAPEX, OPEX and RISKEX occurs during different times in the field-life. The net present value of future costs is used to take the time value of money into account. The lifecycle cost is calculated by:

$$Lifecycle\ \ Cost = CAPEX + OPEX + RISKEX + RAMEX \ = CAPEX + \sum_{k\in\{1,N\}} \frac{OPEX_k}{(1+r)^k} + \sum_{k\in\{1,N\}} \frac{RISKEX_k}{(1+r)^k} + \sum_{k\in\{1,N\}} \frac{RAMEX_k}{(1+r)^k}$$

where $OPEX_k$, $RISKEX_k$, $RAMEX_k$ represent the OPEX, RISKEX and RAMEX in year *k* respectively, *r* is the discount rate and *N* is the field-life in years.

The various cost elements are defined as follows:

CAPEX: Includes material cost and costs associated with installation

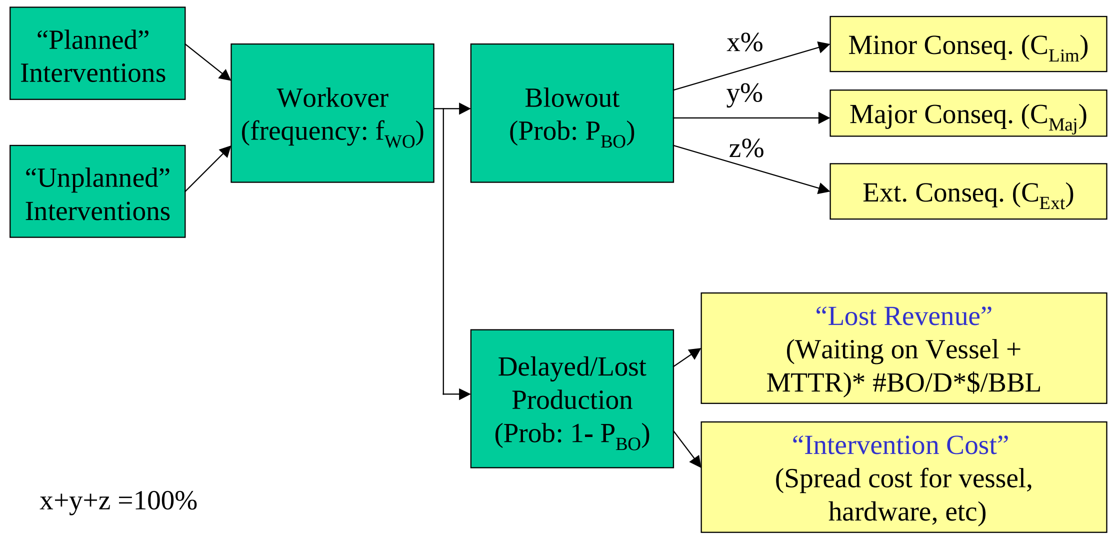
OPEX: Includes intervention costs associated with “planned” interventions, i.e. re-completions caused by depleted reservoir zones.

RISKEX: Includes risk costs associated with blowouts

RAMEX: Includes lost revenues and intervention cost associated with “unplanned” intervention, i.e. interventions caused by component failures such as sand controls system failures, tubing leaks and production tree valve failures.

The RISKEX and RAMEX element is further illustrated in Figure 2.1.

Figure 2.1: RISKEX and RAMEX Calculation Approach



The method by which these cost elements are calculated is described in the following sub-sections.

2.3.1 Operating Expenditures (OPEX)

Each of the identified intervention procedures are broken into steps. The duration of each step is estimated based on a combination of historical data and expert judgement. This is further documented in Section 5. The non-discounted OPEX associated with a re-completion is estimated as:

$$OPEX = (Intervention\ Duration)\ x\ (Vessel\ Spread\ Cost)$$

2.3.2 Risk Expenditures (RISKEX)

The probability of failure of the well completion system is a function of the probability of failure during the various operating modes (drilling, completion, normal production, workovers and re-completions). The lifetime probability of a blowout is calculated as:

$$P(BO\ during\ lifetime) = P(drilling) + P(initial\ compl.) + P(prod) + \sum P(WO) + \sum P(re-compl.)$$

The cost of a blowout depends on the size of the release ("Limited, "Major" or "Extreme"). The Risk Cost (RC) associated with a certain activity (*j*) was calculated as:

$$RC(j) = \sum_{i \in \{limited, major, extreme\}} Prob_i\ (activity\ \ j) \cdot C_i$$

where *Prob*$_i$*(activity j)* is the probability of a blowout of size *i* during activity *j*, and C_i is the cost of leak of size, $i \in$ {limited, major, extreme}. This is further described in Section 7.

2.3.3 Reliability, Availability and Maintainability Expenditures (RAMEX)

The RAMEX is divided into two:

- Cost associated with lost revenues
- Cost associated with interventions

For the model developed, the consequence for the production in a given year depends on the following:

- The production rate at the time the failure occurred
- Lost capacity while waiting on repair resources
- Availability time for the repair resources
- Mobilization time for the repair resources
- Active repair time

An example is given below:

Example 1:

- *Failure: Workover (WO) required to repair the failure in year*
- *Resource: Rig*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO.*
- *Production rate: 10,000 BOPD in year 3.*
- *Lost volume:* $(0.5*90 \text{ days } + 1*30 \text{ days})*10000 \text{ BOPD} = 750{,}000\text{BBL}$

The financial consequence of a well failure will in addition to the factors discussed above depend on:

- Failure time
- Oil operating margin in year produced ($/BBL)
- Spread cost for intervention vessel ($/day)

An example is given below:

Example 2:

- *WO required to repair the failure*
- *Resource: Rig*
- *Failure time: year 3*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO*
- *Production rate: 10,000 BOPD in year 3*
- *Spread cost for Rig: $100,000 per day*
- *Oil operating margin in year produced: $10/BBL*
- *Discount rate: 15%*
- *Financial Consequence (FC):*

$$FC = Lost\ Revenues + Intervention\ Cost$$

$$FC = (0.5*90days + 1*30days)*10{,}000BOPD*\frac{\$10\ per\ BO}{(1+0.15)^3} + \frac{\$100{,}000/d*30days}{(1+0.15)^3} \approx 4.9MM + 2MM = 6.9MM$$

The RAMEX calculations are described in more detail in Section 8.

2.3.4 Input Data

The main data entry items are described in the following subsections. Example values are included for illustration only and can be modified as required in the developed spreadsheet tool.

2.3.4.1 Field Data

(a) General:

Parameter	Example Values
Fieldlife (years)	20
Wells – Dry Tree Tieback Type	Dual Casing Riser System
Wells – Subsea Tieback Type	Horizontal
Wells – Platform	SPAR*
Wells – Number of Dry Tree Wells (#)	12
Wells – Number of Subsea Wells (#)	4
Wells – Water Depth for Dry Tree Wells (feet)	5000
Wells – Water Depth for Subsea Wells (feet)	6000
Wells – Zone Depth for Dry Tree Wells (feet BML, measured)	10000
Wells – Zone Depth for Subsea Wells (feet BML, measured)	8000
Flowline size (inches)	12
Flowline length (miles)	20
Infield Extension (miles)	5
Facilities Production Capacity Limit (M BOPD)	100
Oil operating margin in year produced ($/BBL)	8
Discount Rate for NPV calculations (%/year)	12

* Dry Tree only

(b) Repair Resource Data:

Parameter	Example Values	
	Availability Time (days)	Spread Cost ($/day)
Rig (MODU) (8 point spread moored)	120	$240,000
Pipeline Installation Vessel (DP, heavy lift capability, etc.)	60	$340,000
Umbilical Installation Vessel	30	$200,000
MSV Spread (Capability to support lightweight packages)	7	$60,000
DSV Spread (ROV only – monitor and visual checks)	5	$30,000
TLP or SPAR Platform Rig	30	$120,000
Wireline or Coiled Tubing Unit	2	$25,000

2.3.4.2 *Production Profile*

The production profile is generated by using a Production Profile Builder. Input to this builder are:

- Type of completion (Dual Casing, Single Casing, Tubing Riser, Conventional Subsea Tree or Horizontal Subsea Tree)
- Type of operation (Initial Completion – Frac Pack, Initial Completion – Horizontal, Workover – Sidetrack Frac Pack, Repair Completion Systems Leaks, etc.)
- Start of initial completion (years)
- Total volume in one zone (MM BBL of oil)
- Initial Production Rate (M BOPD)
- Decline rate (% per year)

Based on this data the time to re-completion (T) due to zone depletion can be calculated according to the following formula:

$$V = 365\int_0^T R_0(1-a)^t\,dt = \frac{R_0}{\ln(1-a)}\left((1-a)^T - 1\right) \Rightarrow T = \frac{\ln\left(\frac{V\cdot\ln(1-a)}{365R_0} - 1\right)}{\ln(1-a)}$$

where

- V = Volume (BBL of Oil)
- R_0 = Initial Production Rate (BOPD)
- a = Production Rate Decline rate per year (%/year)

The principle adopted in this study is further illustrated in Figure 2.2 and the profile for each well is added together for each year to generate a total field production profile.

Figure 2.2: Time to Re-Completion – Calculation Principles

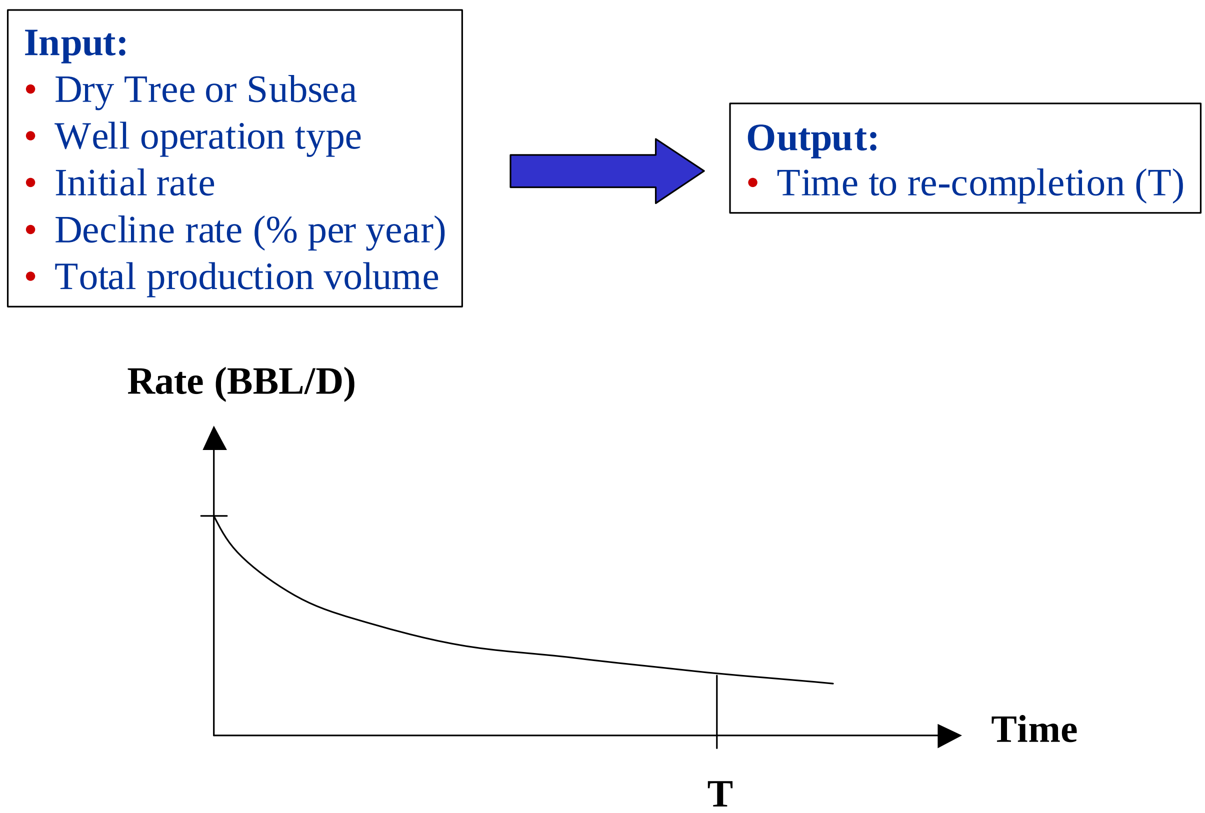
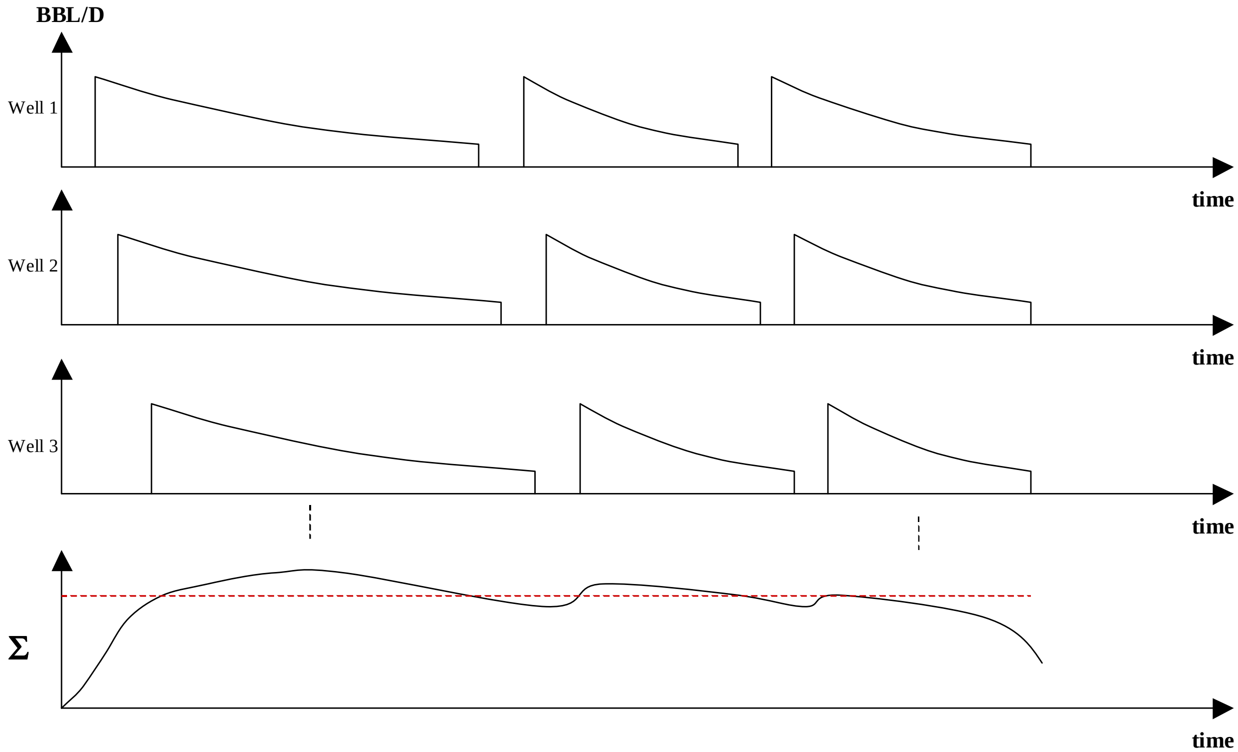
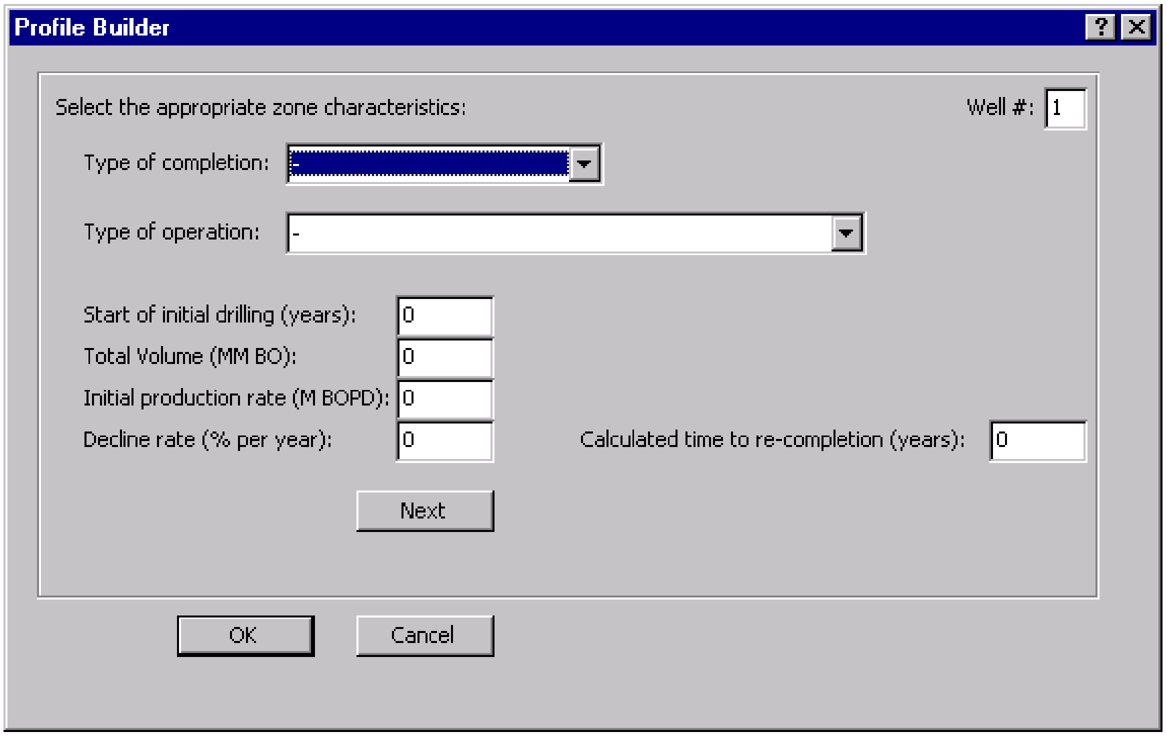


Figure 2.3: Production Profile Generated Based on Individual Zone Depletion



The Production Profile Builder Dialog Box in the JIP developed spreadsheet tool is shown in Figure 2.4.

Figure 2.4: Production Profile Builder Dialog Box

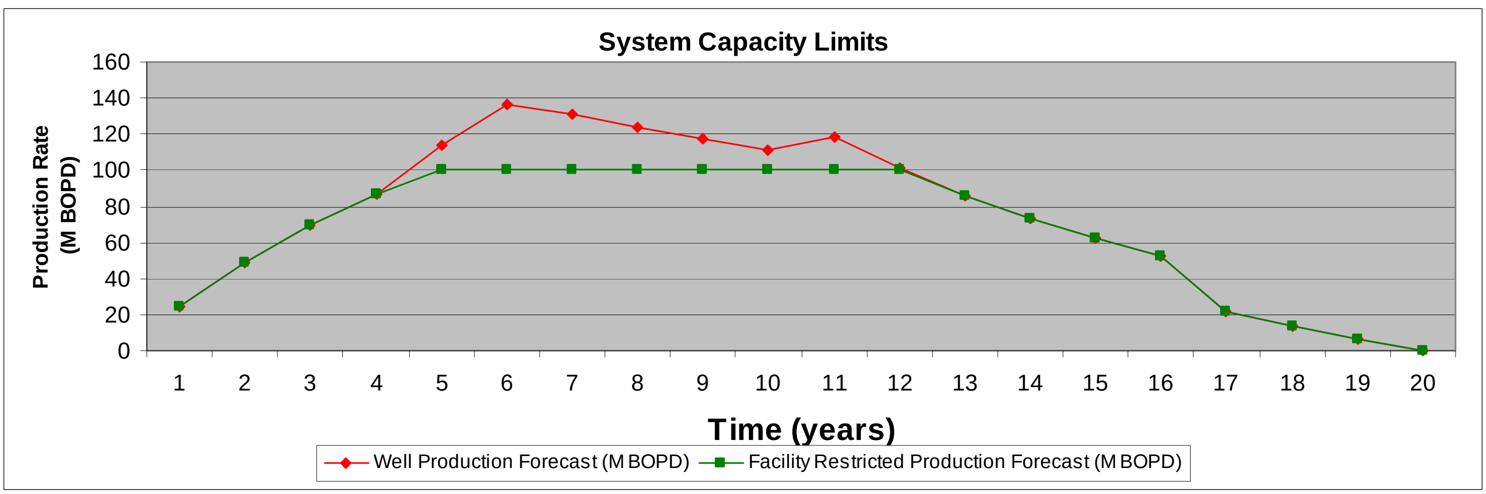


An example of production profile generated is shown in Figure 2.5 and Figure 2.6.

Figure 2.5: Production Profile – Table Format

Well	Forecast Well Production Rates - Average Daily Production Rate for Each Year (M BOPD)																			
Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
All Wells	25	49	69	87	114	137	131	124	118	112	119	101	86	73	62	53	22	14	6	0
1	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	10.0	8.5	7.2	6.1	5.2	4.4				
2	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	10.0	8.5	7.2	6.1	5.2	4.4				
3	0.0	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	10.0	8.5	7.2	6.1	5.2	4.4				
4	0.0	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	10.0	8.5	7.2	6.1	5.2	4.4				
5	0.0	0.0	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	10.0	8.5	7.2	6.1	5.2	4.4				
6	0.0	0.0	12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	10.0	8.5	7.2	6.1	5.2	4.4				
7				12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1			
8				12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1			
9					12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1		
10					12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1		
11						12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1	
12						12.4	12.0	10.2	9.0	13.4	11.4	9.7	8.2	7.0	6.0	5.1	4.3	3.7	3.1	

Figure 2.6: Production Profile – Graph Format



3 SUBSEA SYSTEM DESCRIPTION

3.1 System Description –Well Satellite Clustered System

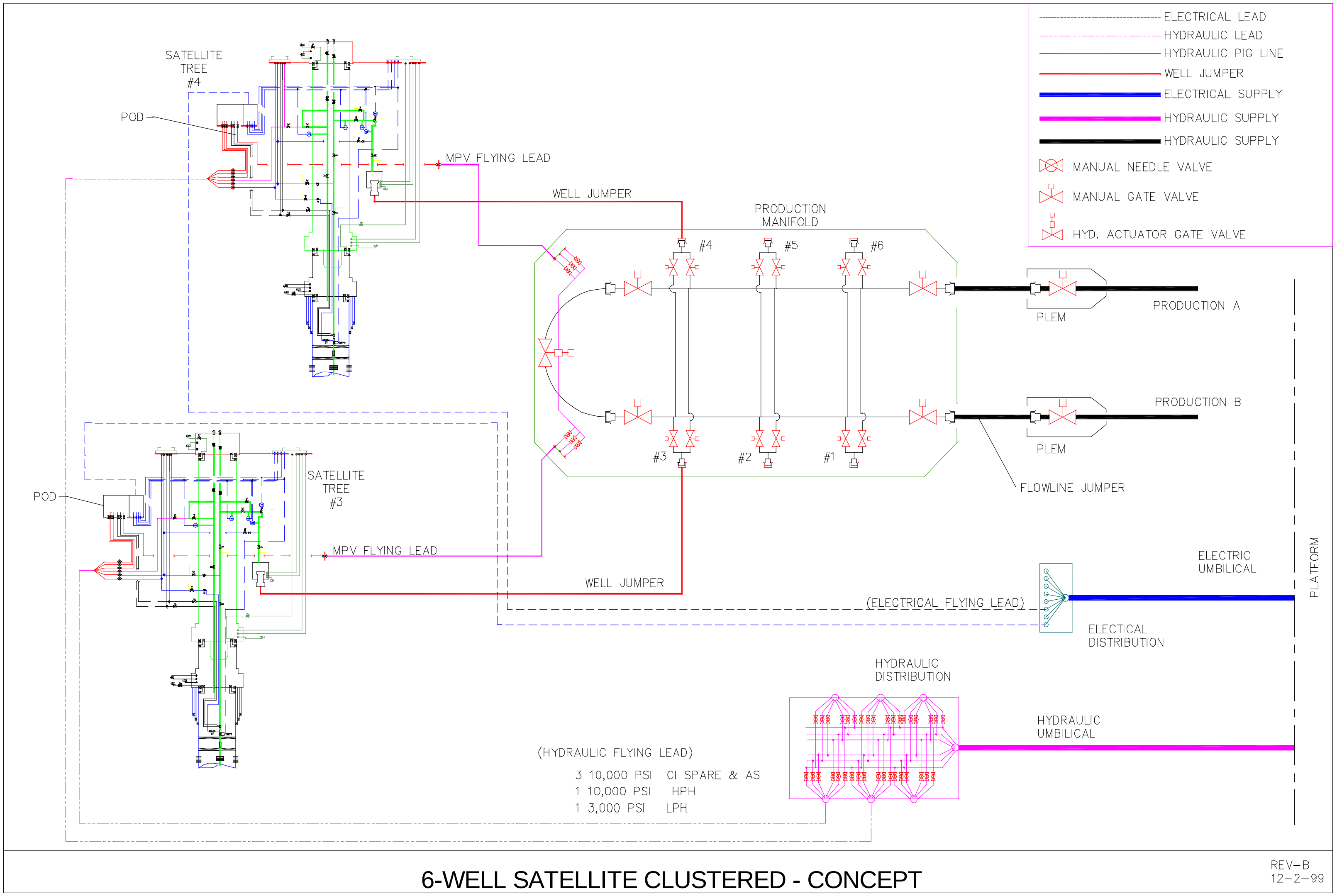
The proposed system will consist of a single six well, piggable, 10,000-psi manifold with dual 6-inch or 8-inch uninsulated export flowline tiebacks to an existing host facility. The proposed system is illustrated in Figure 3.1. The flowlines will initiate at the platform with the second end using a conventional Pipeline End Module (PLEM) in the deepwater section. It is assumed that the installation sequence will allow the flowlines and umbilicals to be installed prior to the manifold installation. The manifold considered will be designed with dual valve block headers that allow independent production access to either flowline. These valves will be hydraulically operated with ROV (remote operated vehicle) override. Each tree pod will control their respective pair of manifold valves via a dedicated flying lead. Manifold design is assumed to be fully rig moonpool recoverable and re-installable. The satellite cluster detailed in Figure 3.1 depicts both the conventional tree and horizontal tree cases.

Flowline Jumpers will connect the manifold to the PLEM’s. Well Jumpers will be used to connect each well to the respective well location on the manifold. Pigging access will only be in the main flowlines – no pigging will be assumed through the tree or jumpers. It is assumed that all hydrate and wax/paraffin blockages will be batch treated with chemicals and/or suppressed using insulation techniques (VIT, annulus blanket, etc.). No through flowline (TFL) capabilities will be assumed for remediation through the tree and/or jumpers.

Utility lines (e.g., chemical injection (CI), annulus vent (AV), low pressure hydraulic (LPH), high pressure hydraulic (HPH), one spare) will be delivered to the field via a main utility umbilical from the production head and will provide discrete distribution of the chemicals (MeOH, paraffin inhibition, asphaltene dispersants, etc.) to each well via flying lead connections from the utility distribution structure to each well.

Tree configurations in the base case will be conventional (dual bore 4 x 2 – 10M) with a standard valve configuration to perform basic operability functions. The well sequences will include unloading single zones to the Mobile Offshore Drilling Unit (MODU). Subsea insert chokes are assumed. The sequence steps will include the overall time and cost estimates for completing the unloading operations and for reaching a pre-determined well clean-up / flowing condition. Instrumentation will consist of pressure/temperature sensors, sand (presence) detection and Permanent Downhole Pressure Gauge (PDPG) with continuity back to the host. Well testing will be conducted by difference and no multiphase meters will be used in the flow stream.

Figure 3.1: Satellite Cluster



Tree configurations in the other case will be horizontal style trees (4 x 2 – 10M) with a standard valve configuration to perform basic operability functions. The well sequences will include unloading single zones to the MODU via the tubing hanger system. Subsea insert chokes are assumed. The sequence steps will include the overall time and cost estimates for completing the unloading operations and for reaching a pre-determined well clean-up / flowing condition. Instrumentation will consist of pressure/temperature (P/T) sensors, sand (presence) detection and permanent down hole pressure gauge (PDPG) with continuity back to the production head. Well testing will be conducted by difference and no multiphase meters or downhole venturi meters will be used in the flow stream.

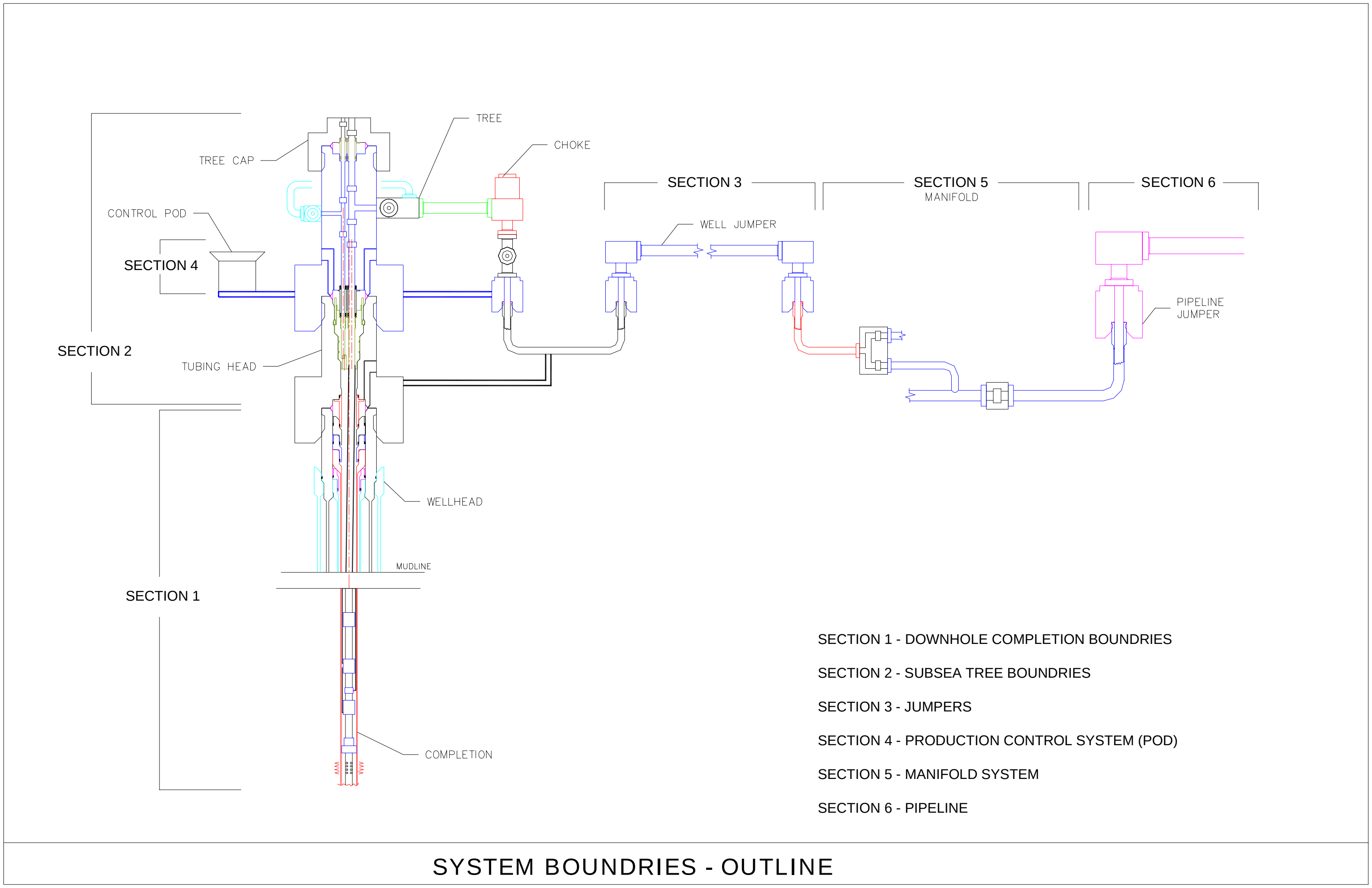
Single flowline valves will be located on the pipeline end manifold (PLEM) to allow commissioning and pressure isolation. These valves are assumed to be buttweld prep end connections to reduce leak paths in the flowline PLEM.

Topside design will be suitable for handling oil/water and gas phase of production at the established rates selected in the DTTAS evaluation.

3.2 System Interface Boundaries

The subsea production system has been configured into various sections (or subassemblies) to provide a reference link to the failure mode identification process. Each section is illustrated in greater definition in the following sections. Major interfaces were identified in both pressure containing and pressure controlling areas such that proper evaluation and assessment could be established between the wet tree and dry tree production systems. The system depicted in Figure 3.2 is the proposed clustered subsea system interface excluding the installation and workover module for both tubing hanger and tree installation modes for a Vertical and Horizontal style completion system.

Figure 3.2: Subsea Production Boundaries



3.3 Conventional/Vertical Tree - Equipment Description

3.3.1 General

3.3.1.1 General Field Arrangement

The subsea development will be offset 35 miles from the host facility. Six wells will be controlled and monitored via a Electro-hydraulic Multiplexed Control system. In–field hydraulic and electrical umbilicals will be independently run from the host and terminated at the subsea end with either a hydraulic distribution manifold (HDM) or electrical distribution manifold (EDM). ROV installable flying leads will provide the interconnection between the EDM and HDM to provide both electrical power and signal to each tree subsea control module and low/high pressure control supply and chemical supply.

The host facility will support the hydraulic power unit (HPU), chemical injection pumps and fluids storage, and surface master control station (MCS). The subsea MCS will be integrated into the host facility main shutdown systems. In the event of a subsea or other disruption, host process operations will trigger a shut-in of the subsea field. Selected levels of ESD (emergency shut down) is beyond the scope of this document and will not be analyzed within the subsea production controls section.

3.3.1.2 Production Control System

The production controls system will control and monitor all sensors and provide a means of remotely operating all hydraulic tree valves, downhole SCSSV, downhole pressure and temperature (P/T) sensors and manifold crossover valves. Hydraulic pressure and electrical power and signal provide the means to communicate with each tree via the E/H mux control pod. The pod is a unit that can be recovered and replaced with lower cost intervention vessels in the event of failure or loss of control. Due to disruption of either the electrical or hydraulic system, the design of the valves is fail safe closed (FSC) allowing complete shut in of the system.

3.3.1.3 Hydraulic Distribution System

The hydraulic distribution system that supports the subsea wells is termed an “open loop” system, which vents pressure at the subsea tree. The vented fluid is a water based hydraulic control fluid. The system will utilize a common LP (low pressure) supply for operation of the FSC valves and a common HP (high pressure) supply to operate the downhole SCSSV valves in each well. The hydraulic distribution system will retain a single spare line in the event of failure within one of the main supply lines. Access to the spare line could be handled via one of the logic interface caps located on the hydraulic distribution manifold.

End termination couplers are assumed to have metal to metal sealing with stainless steel tubing in all the hydraulic and chemical distribution lines on the HDM and tree. Manual isolation valves were assumed for the hydraulic distribution manifold, this simplifies the design.

3.3.1.4 Electrical Distribution System

The electrical system will utilize common power and signal cable that will be combined via a single dedicated pair of electrical conductors. Each well will have a single pair of electrical conductors that will be used as the main power and signal conductor between the SCM (subsea control module or "pod") and the host facility master control station (MCS). Electrical flying leads will be installed using the ROV and "wet" mateable connectors on the tree and electrical distribution module (EDM) .

3.3.1.5 System Interfaces

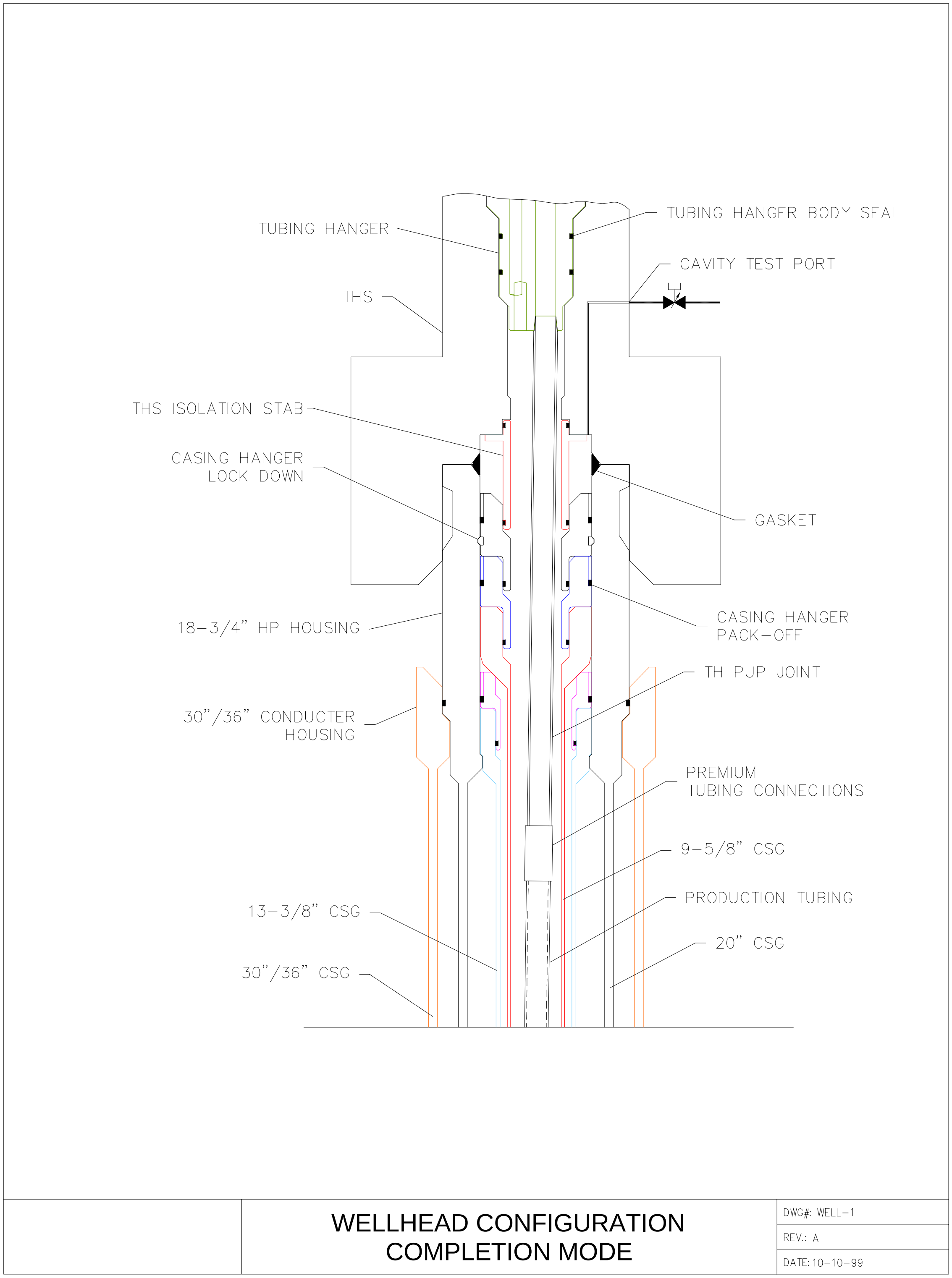
Within the analysis of the system failure modes, the production control system was broken down into discrete interface areas that combined the resulting failure probability of each connection (either hydraulic or electrical) and the associated assembly failure of the control pod, high pressure unit (HPU), chemical injection system, and umbilicals (either hydraulic or electrical). This combined assessment provides a reliability factor for the design which is integrated into the service reliability of the subsea system. Failures of sensors and selected monitoring devices do NOT always warrant an active intervention. Measurements or monitoring can often be achieved via alternative means.

3.3.2 Wellhead System

The subsea wellhead system provides the foundation support for all casing strings and a method by which the casing annuli can be sealed and tested. The well is supported by an outer structural casing that transfers all the bending, induced moments into the surrounding soil environment. The main component of the system is the wellhead housing. This large, high pressure component houses all of the internal casing hangers and packoff assemblies. The 18 ¾" wellhead housing provides the main connection with the BOP connector and Tree connector. The wellhead system detailed in Figure 3.3 highlights the main components of the system.

The system design requires a dedicated tubing head spool (THS) that provides an interface to the jumper connection system, and interfaces with the wellhead and tubing hanger systems. Figure 3.3 also highlights the THS connector interface with the wellhead.

Figure 3.3: Conventional Tree - Wellhead System



3.3.3 Tubing Hanger System

The tubing hanger (TH) system is a conventional dual bore design and will be installed via a conventional 18 ¾" – 10M BOP stack. The tubing hanger is detailed in Figure 3.4. The TH will utilize a direct acting workover control system while in the workover mode. The TH will be landed in a lockdown profile in the wellhead and will seal to the wellhead, thereby isolating the production casing hanger packoff. The system will be fully locked and preloaded to resist thermal expansion loading effects of the tubing to tree interface. The TH will provide both a 4-inch and 2-inch vertical access bore with positive wireline set plug preps. Additionally, the TH will allow a remote connection to be made between the tree and TH for PDPG connections.

A dual tubing workover riser and direct hydraulic (DH) control system will be used to install and test the TH system. The workover riser will consist of a dedicated production and annulus bore riser system with vertical annulus access. The well will not be unloaded in the TH mode, it will only be unloaded in the tree mode. Downhole chemical injection mandrel and SCSSV lines will penetrate through the TH system. The TH will be installed using a tubing hanger running tool (THRT) and BOP spanner assembly to allow upper annular packoff using the BOP stack. The proposed configuration is detailed in Figure 3.5.

Figure 3.4: Conventional Tree - Tubing Hanger

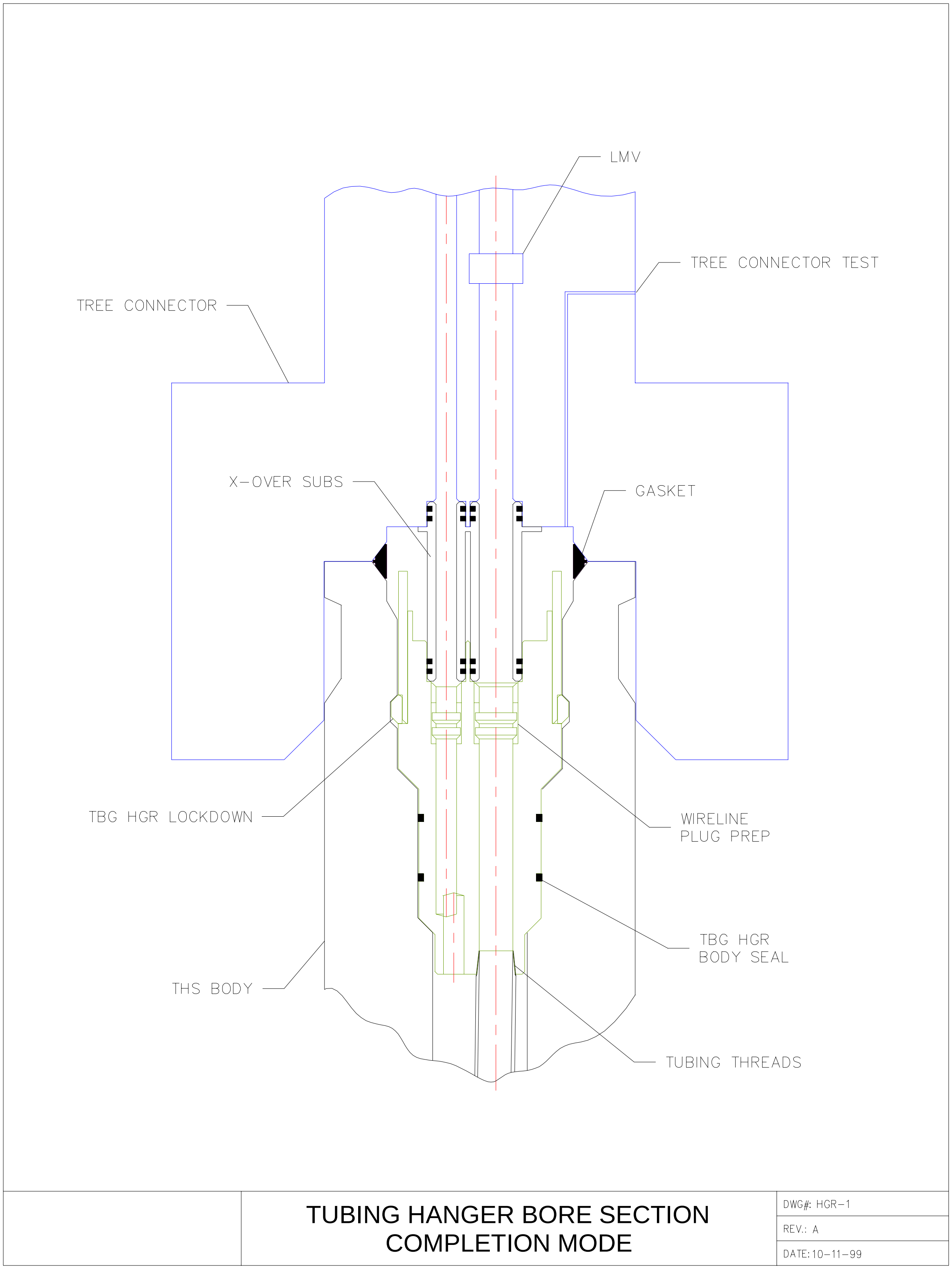
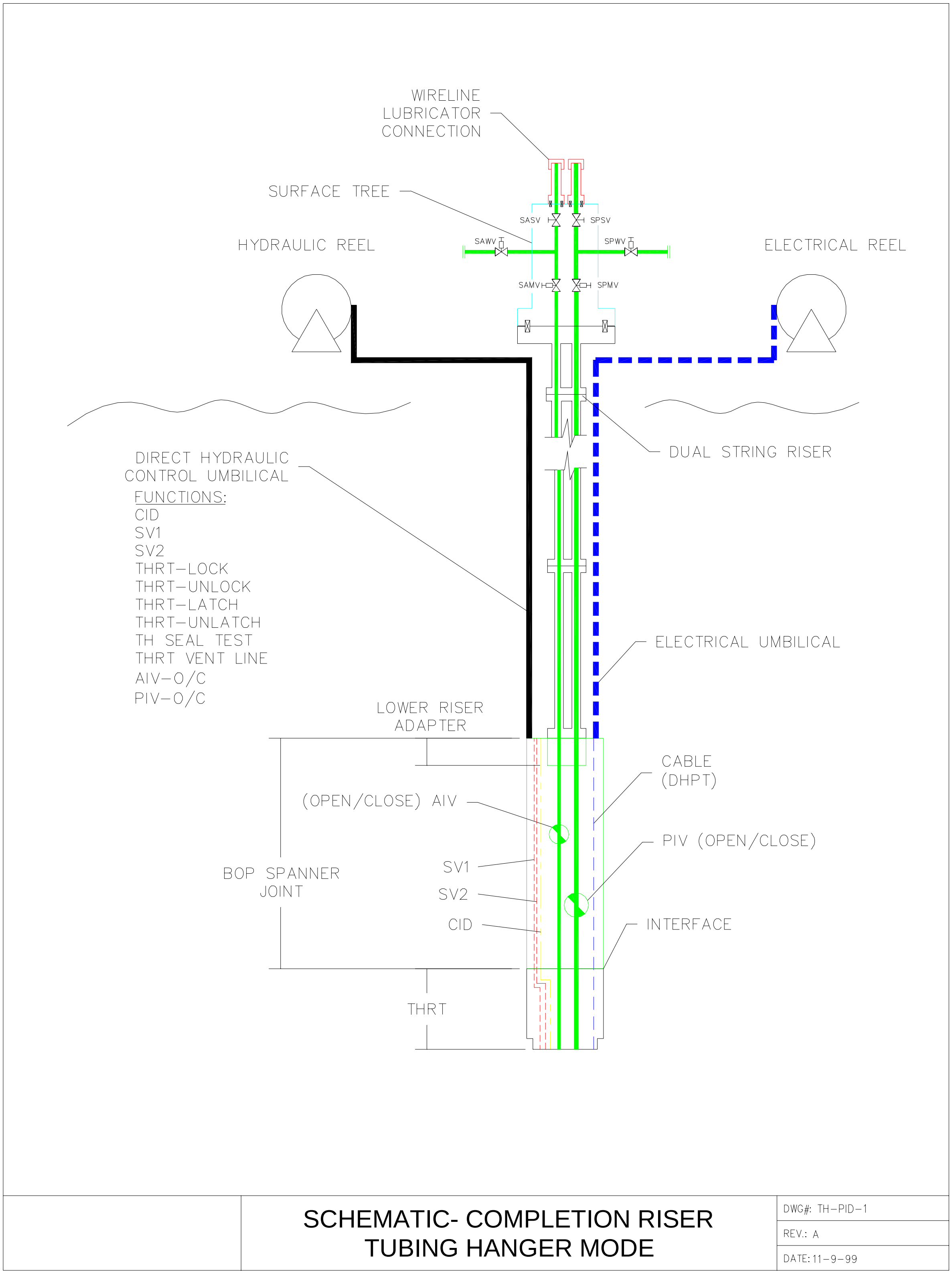


Figure 3.5: Conventional Tree - Completion Riser – Tubing Hanger Mode



3.3.4 Production Tree System

A conventional tree system will be configured using a 4” x 2” configuration. The tree consists of 4” vertical access production bore with wireline plug access to the TH via the tree. The annulus bore will be 2” nominal with direct wireline access to the TH annulus.

Base case configuration of the tree valves will be for the production mode: lower master valve (LMV), production safety valve (PSV), production wing valve (PWV), chemical injection downhole (CID), chemical injection tree (CIT), pressure/temperature sensor (P/T - 2 - production side), pressure/temperature sensor (P/T -1 - annulus), crossover valve (XO), Choke, flowline isolation valve (FIV), annulus master valve (AMV), annulus swab valve (ASV), and annulus wing valve (AWV). The tree will interface with an 18 ¾” –10M working pressure profile (typical wellhead interface seal – VX, AX, etc.). The design will use a dedicated tubing head spool to allow the system to be compatible with guidelineless (GLL) operations for both drilling and completion. The proposed tree is detailed in Figure 3.6.

The production control system will be E/H Multiplex (Mux) with flying lead connections between the tree and the electrical and hydraulic distribution manifold. The production control system will be operated from the production host via the electrical and hydraulic umbilical infrastructure. Back up contingency for power and signal will be inherent in the design to ensure dual redundancy for the controls. Remote vertical access to the control pod via a mobile offshore drilling unit (MODU) or multi-service vessel (MSV) will be assumed.

It is assumed that the flowlines will be designed to the maximum working/testing pressure of the system, however, during startup and shut down it is assumed that choking is required. ROV insert chokes (4” – 10K) are assumed for the base case design. MODU and/or MSV interface for recovery in a GLL will be the primary method of remediation and intervention. The chokes are to be operated via the E/H (Mux) production control and will not be required to be functional via the workover control system. All control line tubing on the tree will be fully welded to reduce leak paths.

All tree valves and stab seals in the system should be designed using metal to metal seals with resilient backup. Testing of all seals and valves will be required prior to installation. All valves will incorporate a metal to metal floating gate design with resilient (non-metallic) single stem seal. No backseat will be required on the valves. With reference to Figure 3.7, the hydraulic valves will be used as shown and should be designed for full 4,000 psi control system pressure actuation. The tree will have ROV override functionality for all valves with standard rotary type interfaces applied. Hot stabs will be used for direct access to test ports and pressure gauge packs.

The following illustration (Figure 3.7) is the Tree Process and Identification drawing for the tree pressure containing and pressure controlling interfaces.

Figure 3.6: Conventional Tree - Tree Boundaries Bore Section

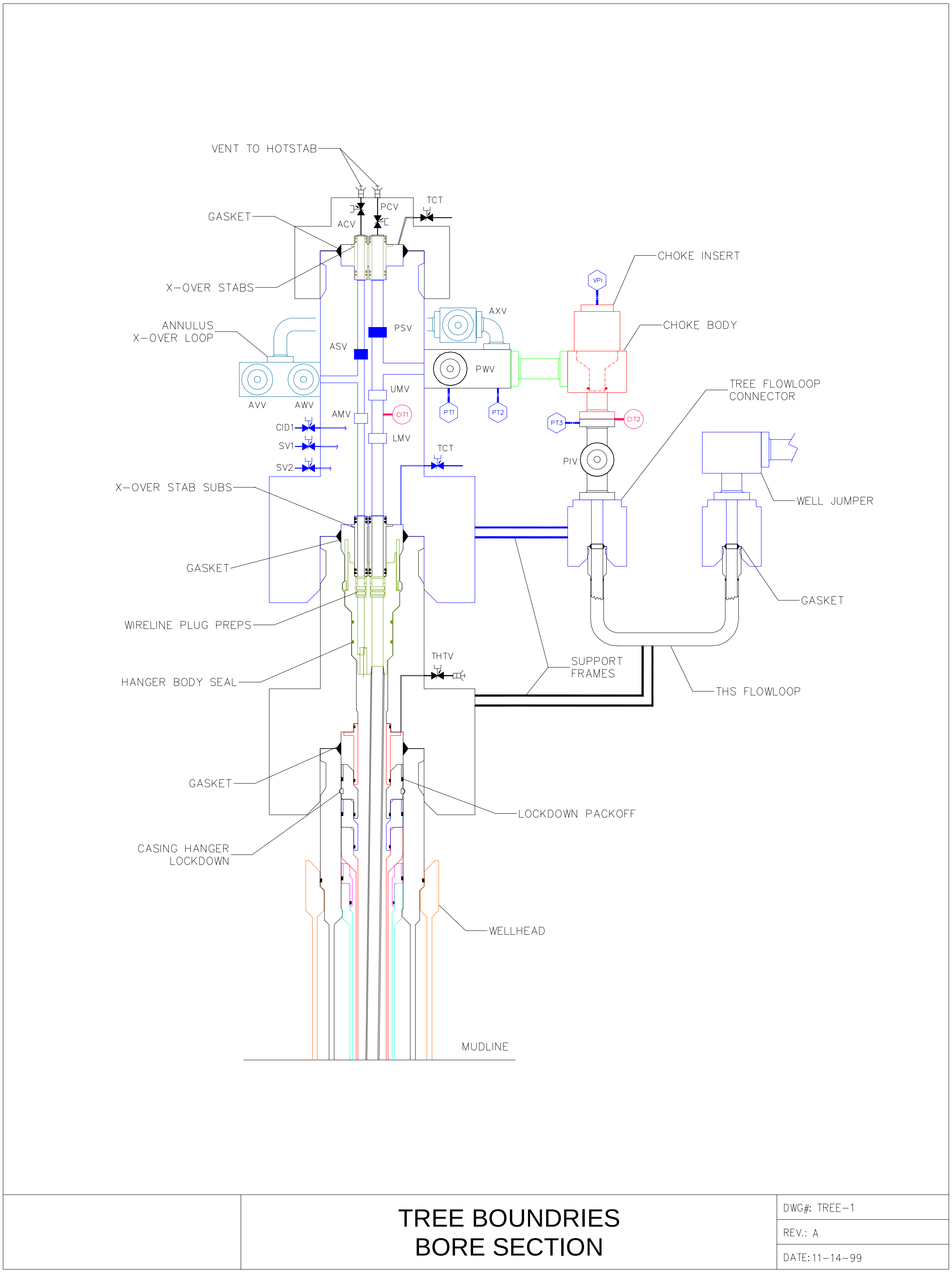
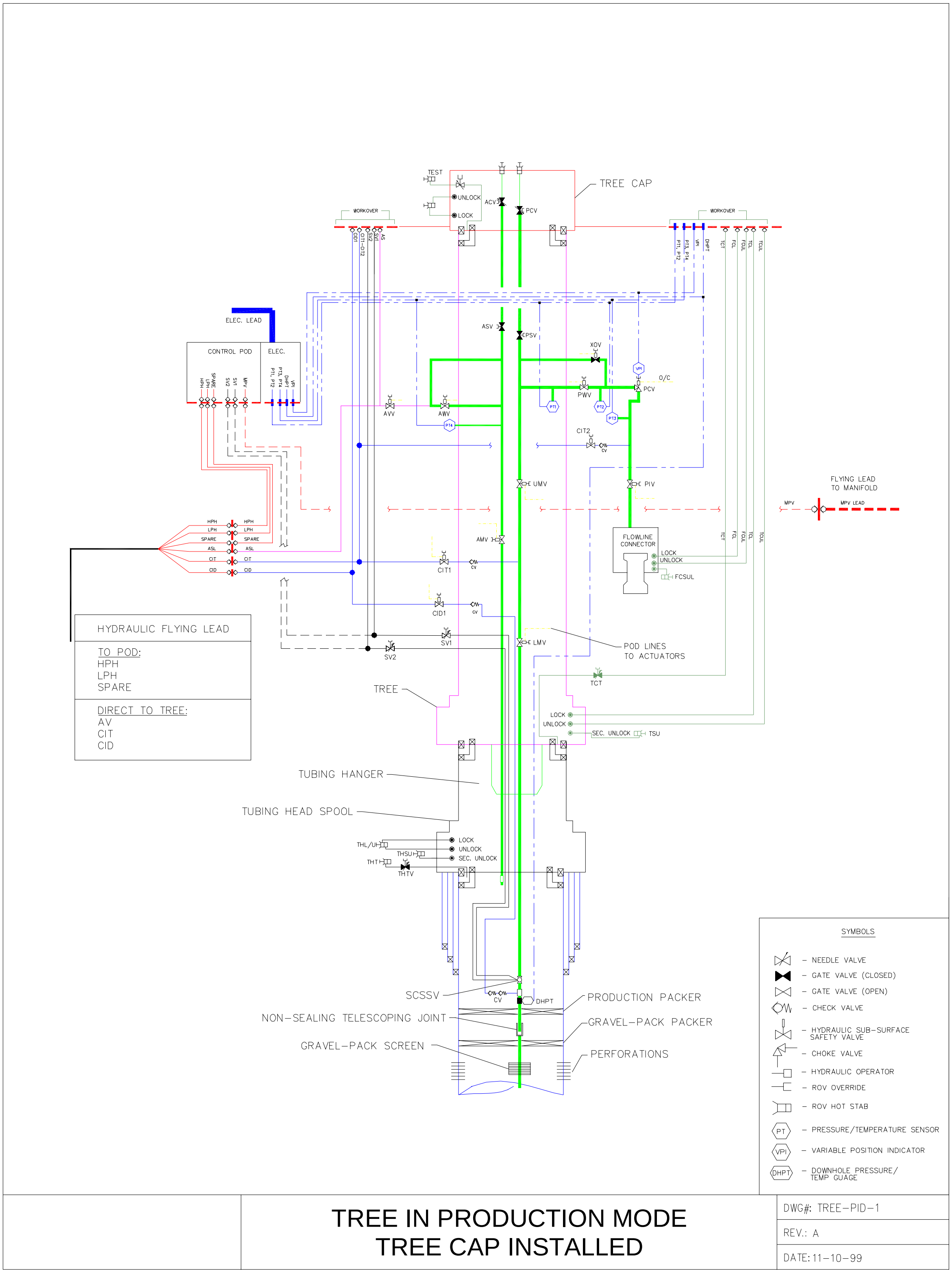


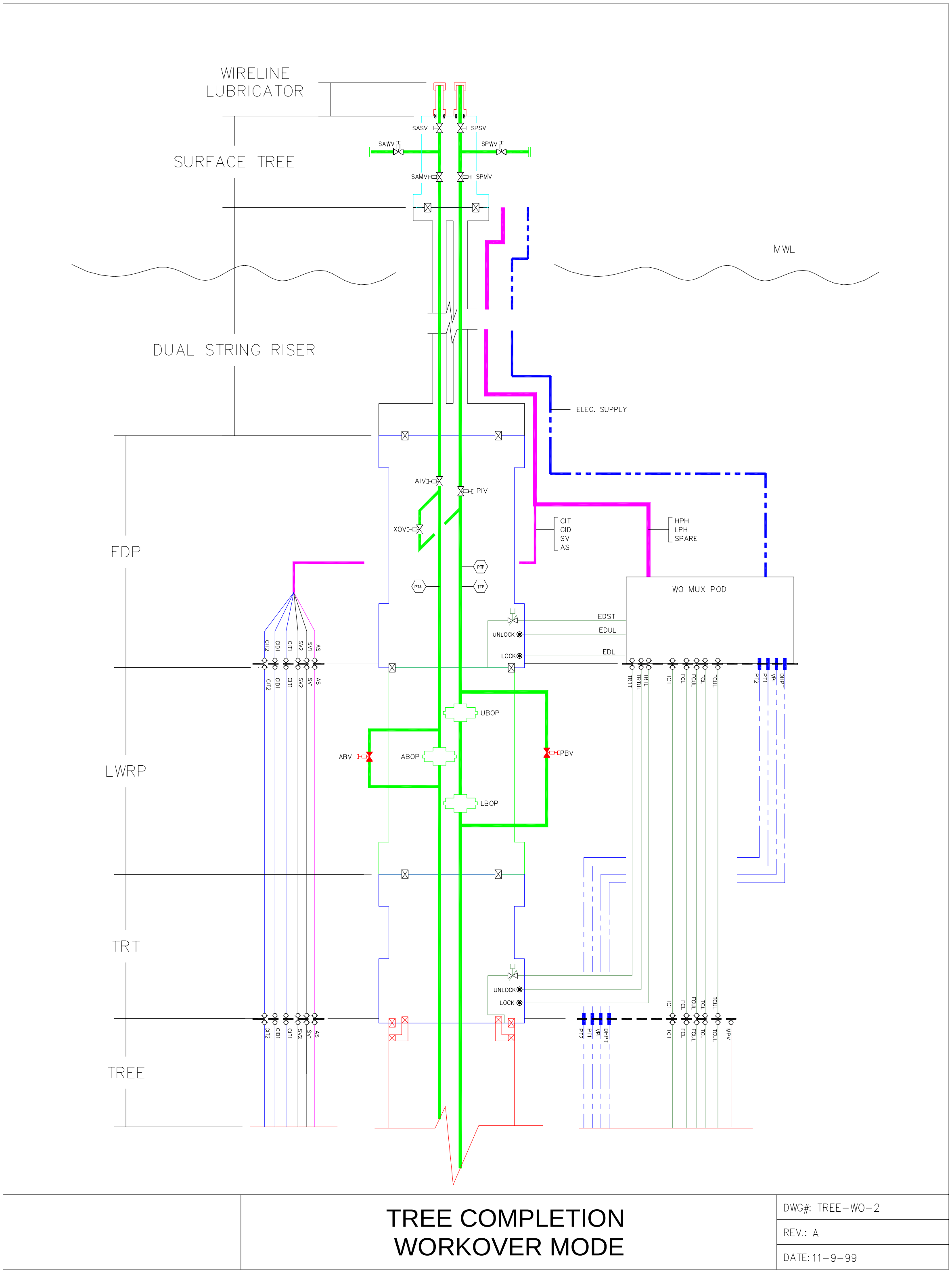
Figure 3.7: Conventional Tree - Tree in Production Mode - Tree Cap Installed



3.3.5 Tree Installation and Workover Control System

Due to the depth requirements for a conventional tree, a dual riser is the assumed base case design requirement. Alternate riser configurations for the workover mode can be applied (i.e., tripping the tree on drillpipe and re-entering using other premium strings or, for the 4,000 foot case, multiple string riser design is an option, but not a preference). The workover control system (WOCS) will be configured to operate all workover control functions inside the emergency disconnect package (EDP), lower workover riser package (LWRP), tree valves, downhole sensors and control lines. The system will be a dual redundant system in relation to power and signal. There is a single source for the hydraulic supply, however, in an emergency case, backup hydraulic accumulator supply will be available. The system will be integrated into the tree and fully tested prior to offshore mobilization and offshore installation. The production and annulus bores will be metal to metal sealing system with resilient backup on all subsea remote connections. All connections made-up at surface will be fully tested. The tree completion in the workover mode is illustrated in Figure 3.8.

Figure 3.8: Conventional Tree - Tree Completion – Workover Mode



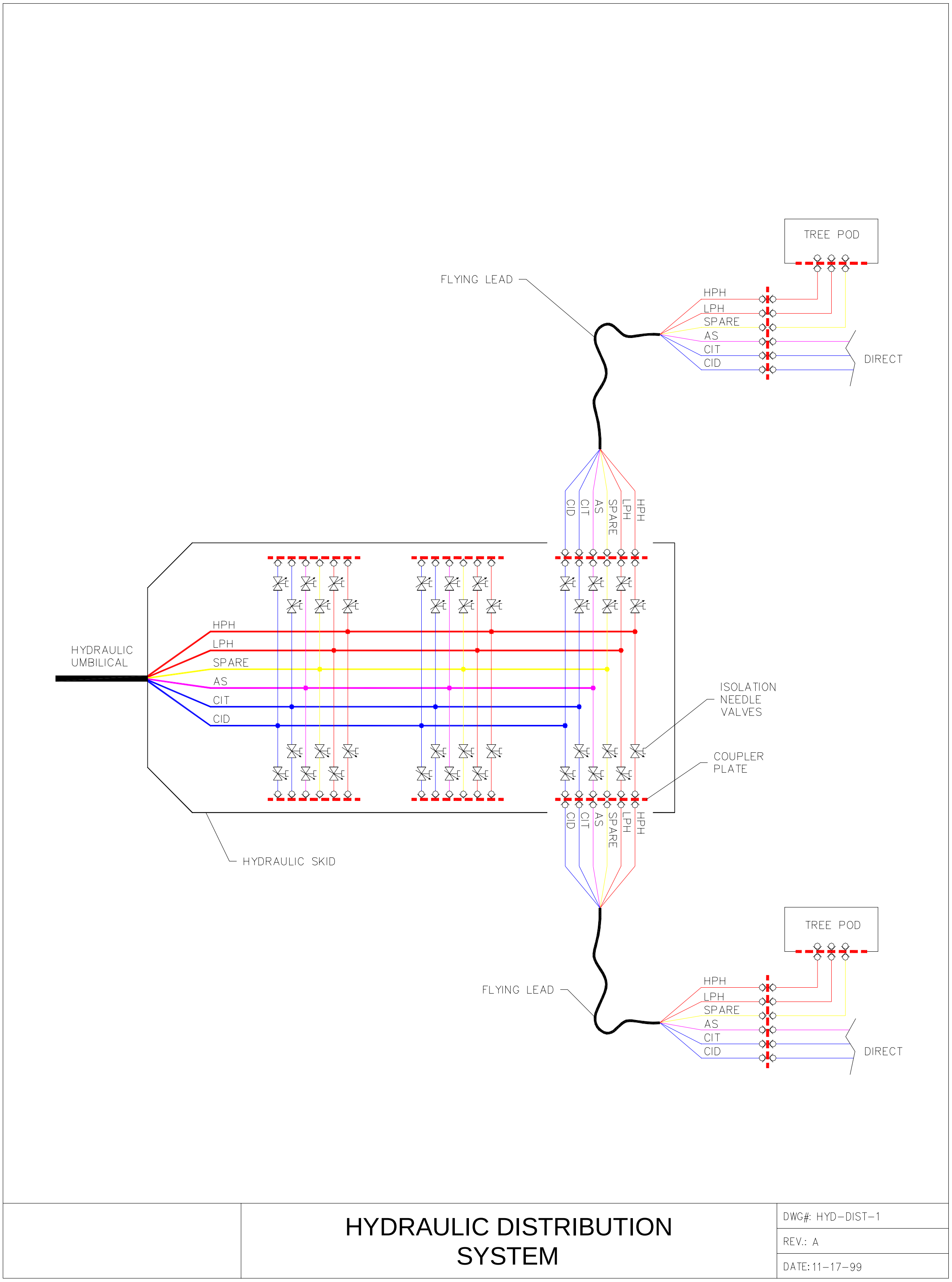
3.3.6 Tree Cap

The tree cap will provide a link from the workover control system (WOCS) to the production mode control system. A hydraulic actuated connector with a series of hydraulic couplers will be simultaneously made up during the installation. Electrical connection between the tree and tree cap will be made during this operation, completely isolating the tree WOCS from operation of the tree. Metal to metal seal barriers with resilient backup rings will provide the backup to the environment as a secondary barrier to the production swab valve (PSV) and annulus swab valve (ASV). Controls for actuation are provided by the ROV or direct hydraulic utility control bundle.

3.3.7 Flying Leads

Both electrical and hydraulic utility requirements will be via independent flying lead connections between the Electrical Distribution System and Hydraulic Distribution System. These connections will be diverless, ROV assisted and completed off the critical path of the rig based MODU operations. Hydraulic couplers will be used for the connection of the chemical injection, annulus swab valve (ASV), low pressure hydraulic, high pressure hydraulic, and spare lines. The electrical connections will be the conventional deepwater wet mateable connections suitable for handling the power and signal requirements of the E/H Mux system. The hydraulic distribution system is detailed in Figure 3.9.

Figure 3.9: Hydraulic Distribution System (valid for Conventional and Horizontal Tree)



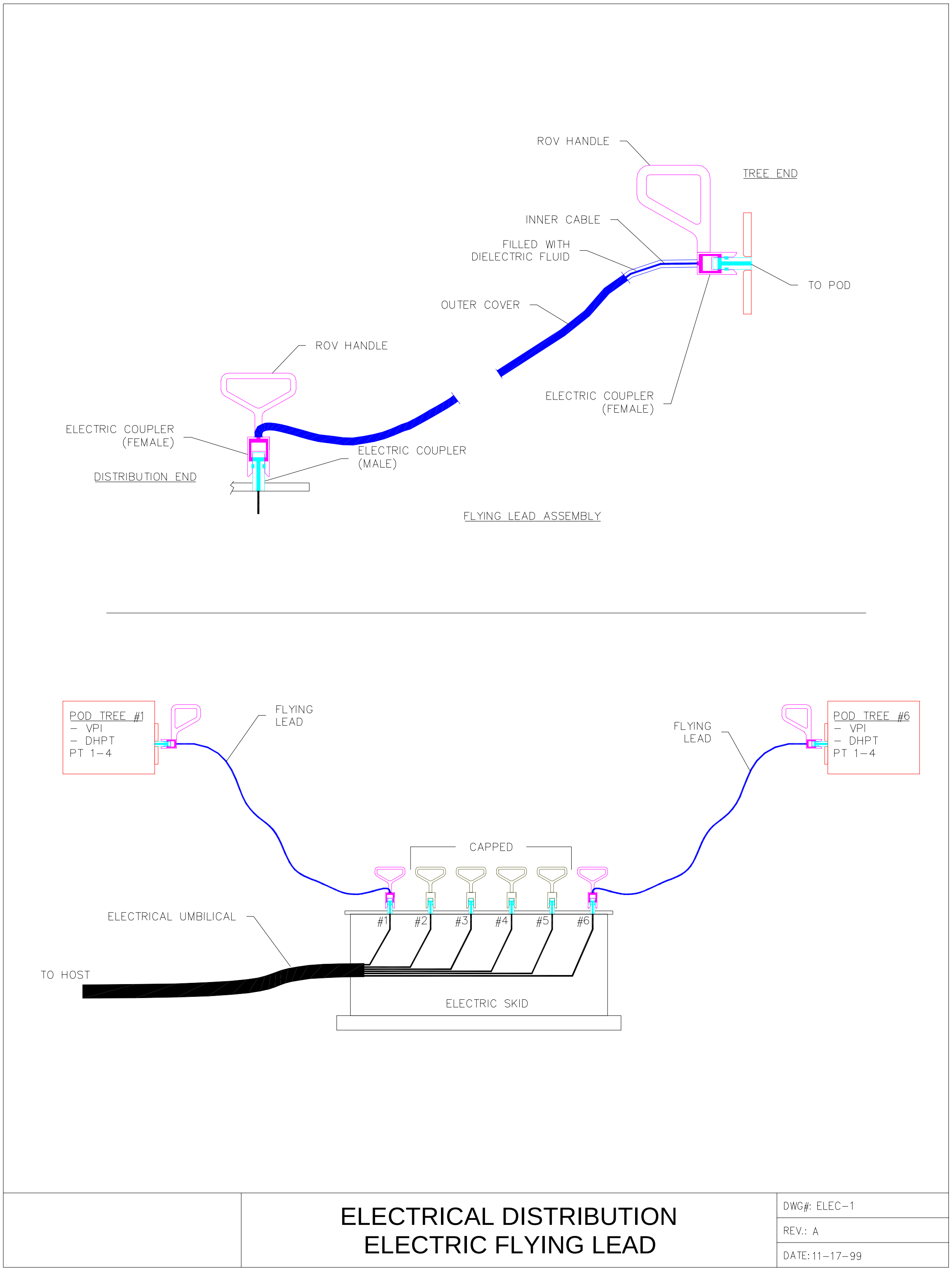
3.3.8 Chemical Injection System

The base case system will rely on a discrete continuous chemical injection system supported by the host platform. The direct lines will supply a deepwater distribution manifold from which jumper interconnections can be made in the event of line loss or failure. The system will not use chemical injection chokes or modules for metering or regulation of the flow. It is assumed that the topside facility will be able to batch treat the chemical supply and have the reserve volumes suitable for the system design. The chemical distribution lines will be routed directly from the host via the hydraulic distribution module.

3.3.9 Electrical Distribution System

The electrical umbilical will be laid as an independent line from the host to an electrical distribution termination. The termination assembly will be in the field location of each well center and will distribute the signal and power requirements to each pod in the field. The basis of the installation approach is that each flying lead will be installed from the rig (MODU) and can be serviced/replaced either from a diving service vessel (DSV) or multi-service service vessel (MSV). The electrical distribution system is detailed in Figure 3.10.

Figure 3.10: Electrical Distribution – Electric Flying Lead (valid for Conventional and Horizontal Tree)

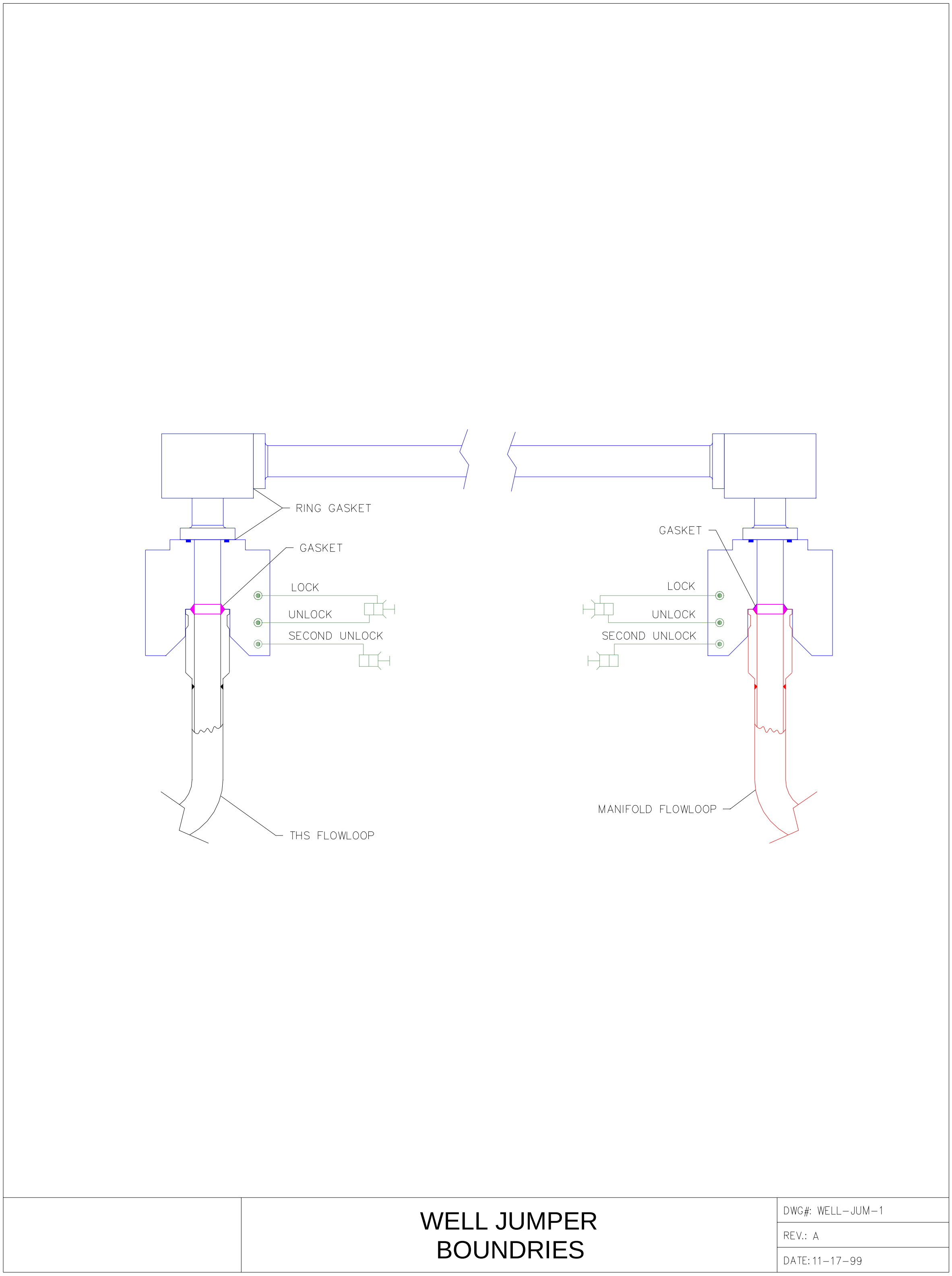


3.3.10 Jumpers (Well Jumpers)

The function of the well jumper is to provide a high-pressure conduit between the tree and manifold. Each well will have full well stream design capability downstream of the startup and shutdown choke. The jumpers will be fully hard piped and will utilize metal to metal seals as a primary barrier with resilient backup. By design, the system will allow for remote seal interchangeability via ROV systems and tooling. Hydraulic control (extend, retract, lock and unlock, seal test, etc.) will be accomplished via the ROV, thus eliminating a dedicated utility umbilical. Well jumpers are expected to be installed via the rig-based operations and should not exceed 80 foot offset distance from the manifold to the clustered well location. By design, the system will allow for complete recovery of the jumper system. The design of the end termination may be vertical or horizontal in nature (outside the scope of this work).

Figure 3.11 highlights the interface areas of each well jumper termination with respect to tree and manifold end connections.

Figure 3.11: Well Jumper Boundaries (valid for Conventional and Horizontal Tree)



3.3.11 Flowline Jumper / Pipeline End Manifold (PLEM)

Base case design approach identifies a flow-wetted interface with the flowline jumper and pipeline end manifold. With the system choke on each tree and manifold pressure adjusted for optimum production rates, the export pipeline end manifold (PLEM) is designed with a manual isolation valve that is typically used for commissioning the pipeline prior to flowline jumper installation. Figure 3.12 illustrates the flowline jumper boundaries and Figure 3.13 illustrates the flowline and PLEM boundaries.

Figure 3.12: Flowline Jumper Boundaries (valid for Conventional and Horizontal Tree)

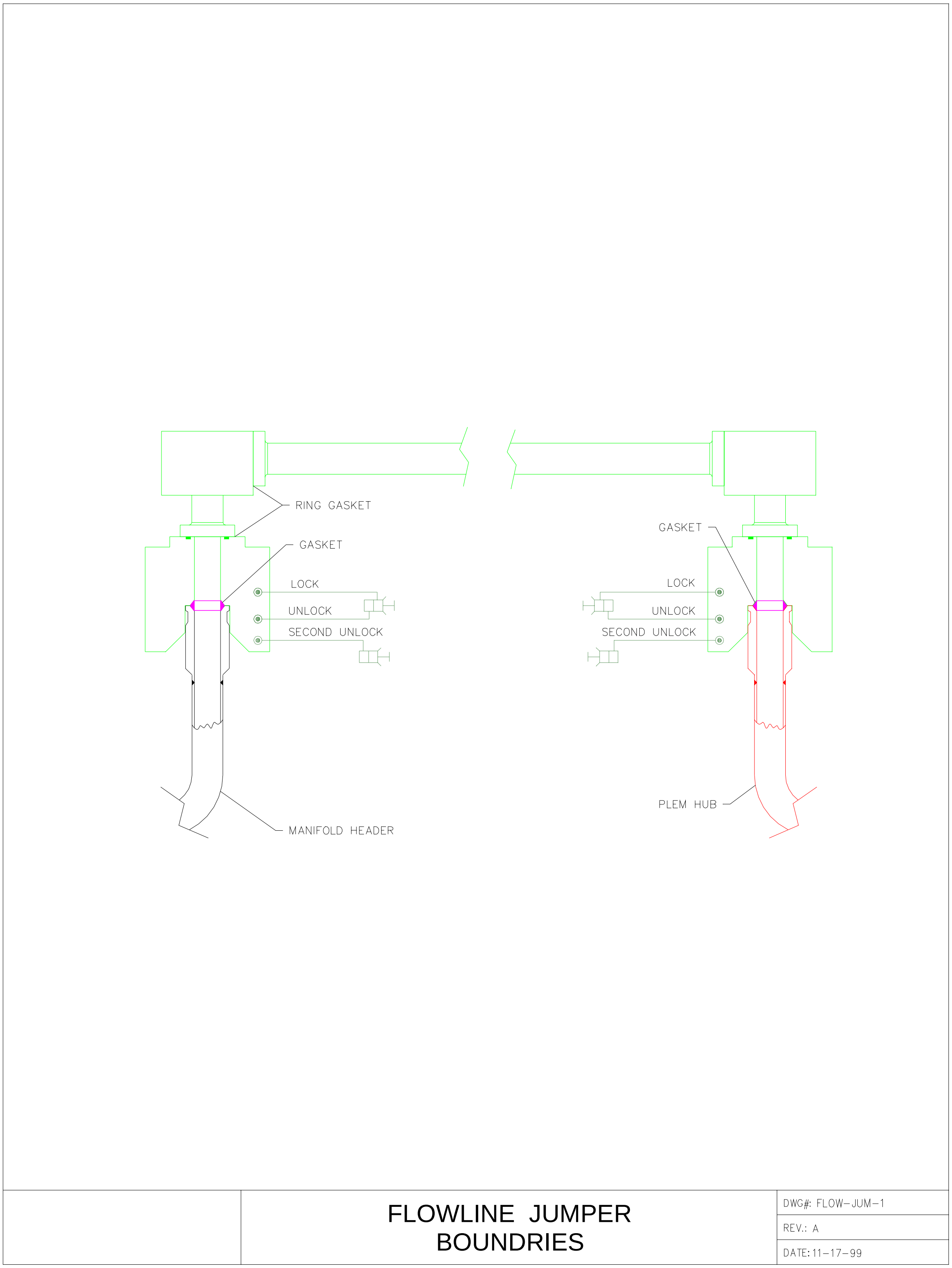
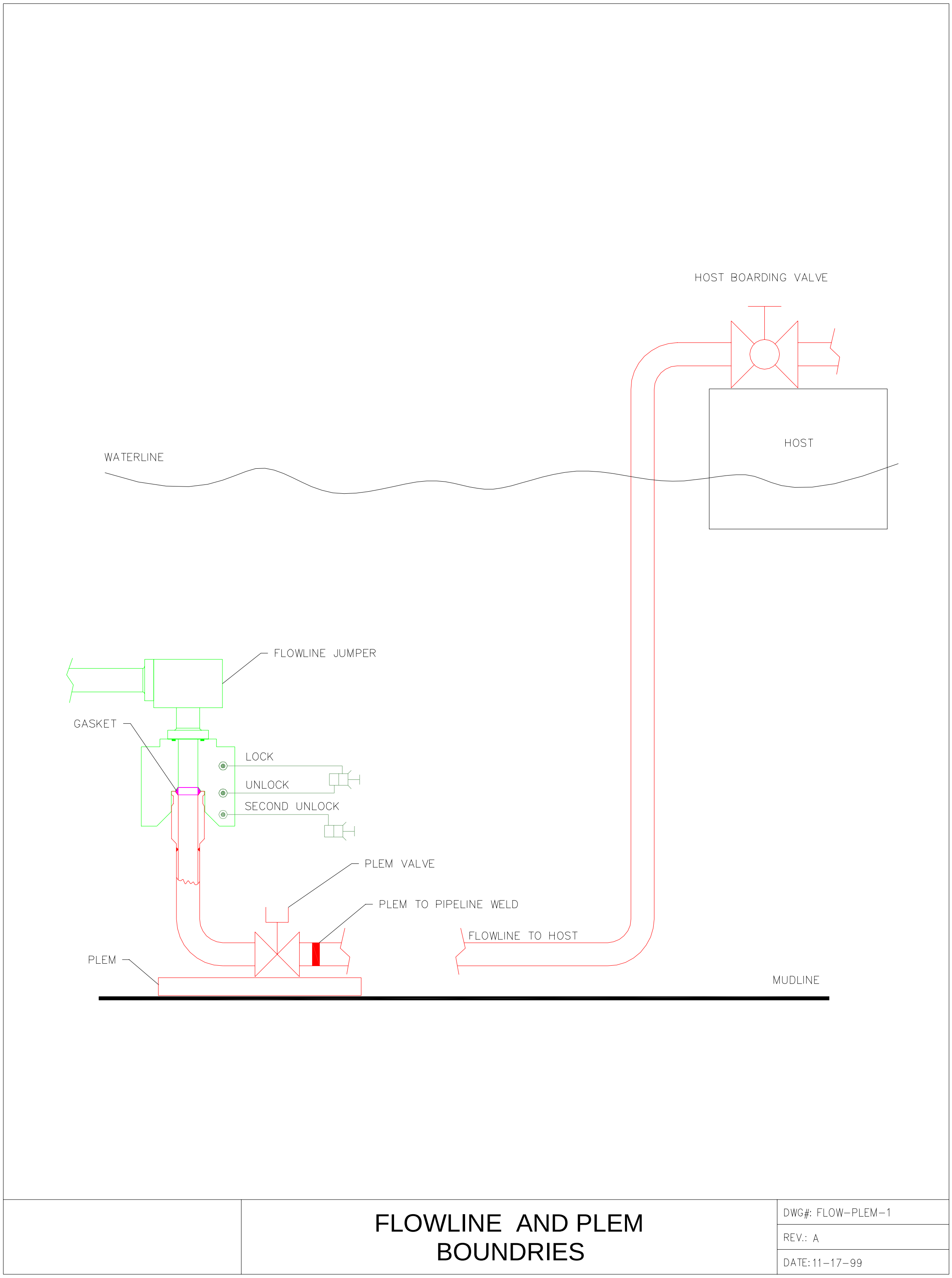


Figure 3.13: Flowline and PLEM Boundaries (valid for Conventional and Horizontal Tree)

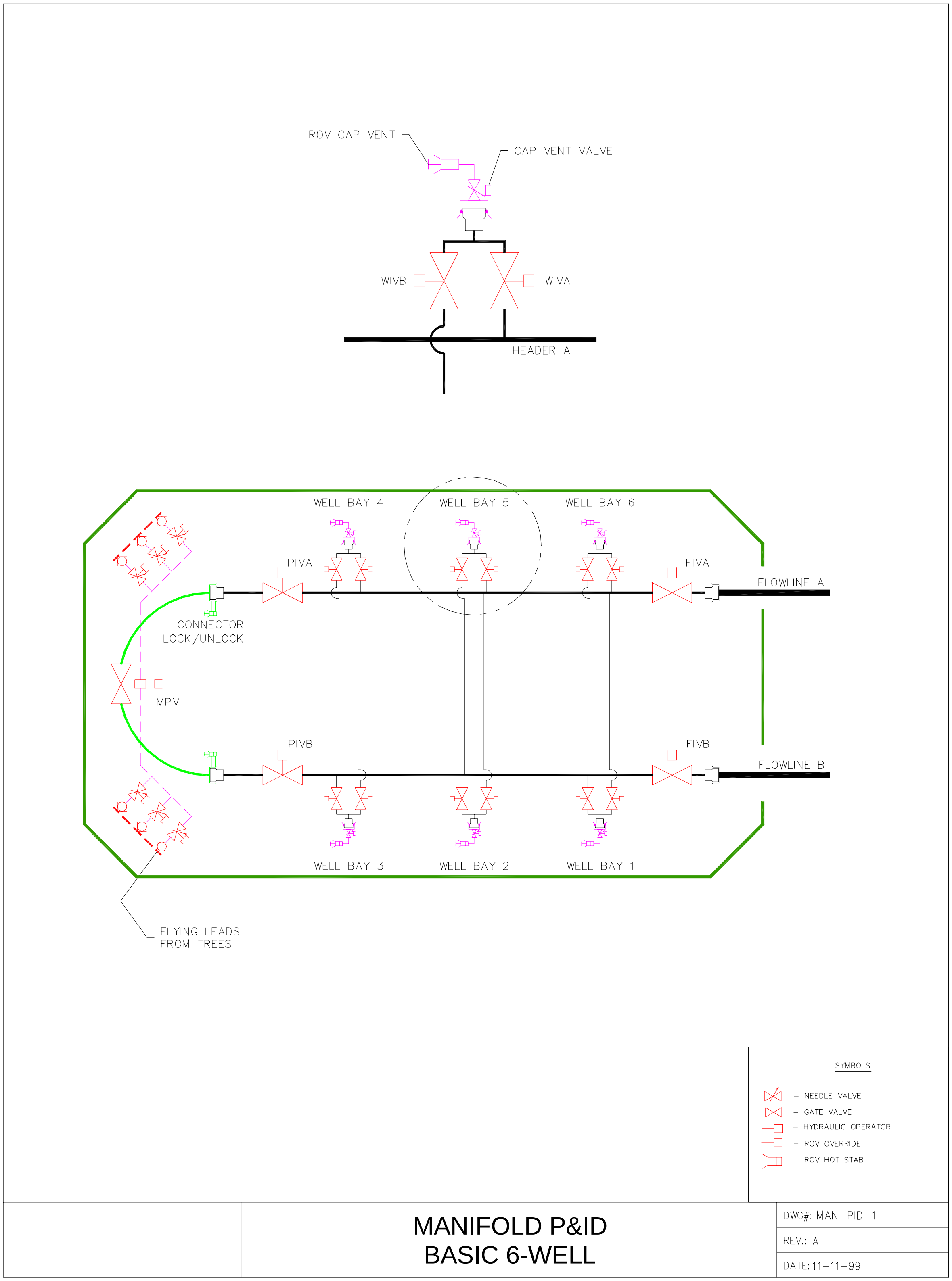


3.3.12 Manifold System

The manifold system is a 6 well – 10,000 psi system with vertical connections at the manifold hubs. The manifold has dual production headers with a pigging loop and a hydraulically controlled isolation valve via each production pod. Each well bay will have dual manual isolation valves to selectively set the production to either header. The pigging loop is 5D (i.e., the bend radius is at least five times the pipe diameter to facilitate pigging operations). Non-productive wellbay slots in the manifold will have pressure isolation barriers creating a dual barrier philosophy during the period in which initial production is initiated.

Installation is expected to be either from a construction service vessel or MODU. The design will allow for remote recovery of the pigging loop from the main manifold assembly. The manifold will be a gravity base structure with skirt pile approach. The manifold is illustrated in Figure 3.14.

Figure 3.14: Manifold P&ID (valid for Conventional and Horizontal Tree)



3.3.13 System Operability & Workover / Intervention

Operations of all the wells will be accomplished via the host platform in the production mode. The system will allow for batch treatment of the produced fluids to mitigate hydrate formation and wax deposition. It is assumed that the system will be uninsulated from the tree to the host and that no vacuum insulated tubing will be run. During shutdown and startup the operations will include full batch treatment of both downhole and tree injection points. Pigging frequency will be based on a predetermined plan and will require ongoing operational review and refinement.

It is assumed that major workovers will be undertaken by a MODU. It is also assumed that minor workovers (i.e., choke replacement, pod replacement failure, valve override operation, etc.) will be conducted via a multi-service vessel (MSV) or diving support vessel (DSV).

3.4 Horizontal Tree - Equipment Description

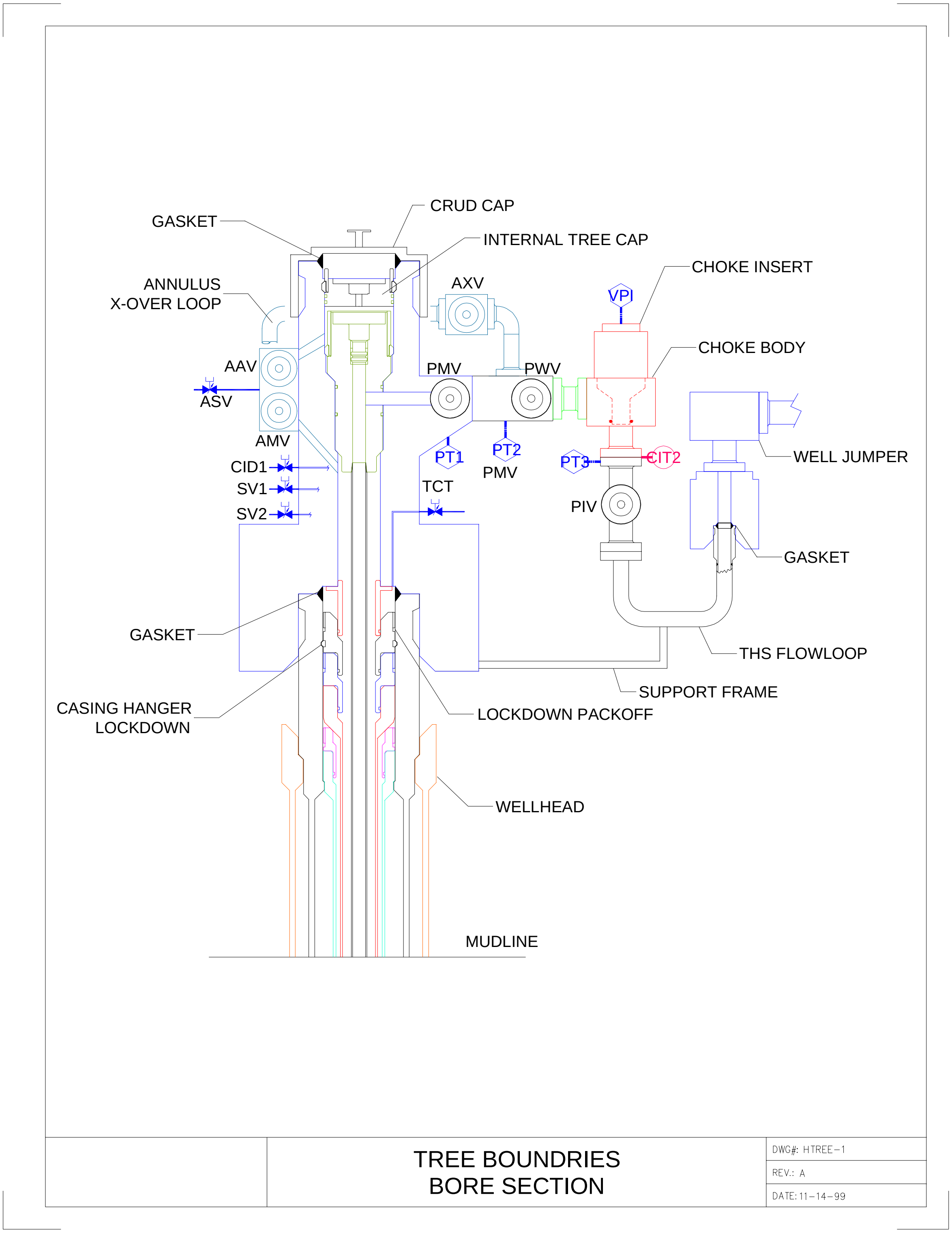
3.4.1 Wellhead System

The subsea wellhead system provides the foundation support for all casing strings and a method by which the casing annuli can be sealed and tested. The well is supported by an outer structural casing that transfers all the bending, induced moments into the surrounding soil environment. The main component of the system is the wellhead housing. This large, high pressure component houses all of the internal casing hangers and packoff assemblies. The 18 ¾" wellhead housing provides the main connection with the BOP connector and Tree connector. The wellhead system detailed in Figure 3.15 highlights the main components of the system.

The horizontal tree connects directly to the subsea wellhead system. The horizontal tree design eliminates a tubing head spool as presently found in the base case vertical tree system. The horizontal tree assembly will carry the flowline hub enabling vertical well jumper connections between the tree and manifold.

Figure 3.15 also highlights the horizontal tree connector interface with the wellhead.

Figure 3.15: Horizontal Tree - Wellhead System



3.4.2 Tubing Hanger System

Horizontal tree systems enable the tubing hanger to be landed after the tree is installed on the wellhead. This allows direct access to the downhole completion system without having to disrupt the tree / wellhead connection and flowline jumper connections. Additionally, this allows conventional 18 ¾” connection interface on top of the tree for BOP stack connections during workover and installation operations.

The TH system is a single bore system used within the horizontal / “spool” tree system and will be installed via a conventional 18 ¾” – 10M or 15M BOP stack. The tubing hanger is detailed in Figure 3.19 (horizontal tubing hanger). The TH will utilize a direct acting workover control system while in the workover mode. The TH can be landed and locked into a lockdown profile in the horizontal tree assembly. The system will be fully locked and preloaded to resist thermal expansion loading effects of the tubing to tree interface.

Another advantage of the horizontal TH is that it provides a single “large bore” tubing capability up to 7” tubing with multiple downhole control line interface between the tree and tubing hanger. Electrical flying lead connections are made up with the ROV system (electrical connection) and mechanical couplers upon landing the tree for the HP / LP and Chemical injection supply between the TH and tree. The tubing hanger will be passively oriented, providing critical alignment for the coupler interface, production exist bore and alignment for ROV horizontal connection to be made for PDPG / smart well connection. Vertical access via high pressure landing string allows for large bore, positive wireline set plug preps.

3.4.3 Tree System

The horizontal tree assembly provides the main environmental barrier between the wellbore and the environment during well production mode. Since the installation sequence is varied between the two styles of completions and trees, the number of barrier and methods by which they are installed and tested become a distinct difference between the vertical and horizontal tree systems.

Horizontal tree system will be configured using a 4” x 2” configuration. The tree consists of 4” vertical access production bore with wireline installed production isolation plug located in the tubing hanger. A secondary isolation barrier will be placed in the internal tree cap upon installation. The annulus bypass loop (2”) will be used to allow pressure equalization below the tubing hanger and annulus circulation in the workover mode.

Base case configuration of the tree valves will be for the production mode: PMV, PS, PWV, CID, CIT, PT (2 - production side), PT (1 - annulus), XO, Choke, FIV, AMV, AS, and AWV. The tree will interface with an 18 ¾” –10M working pressure profile (typical wellhead interface seal – VX, AX, etc.). The system will be compatible with guidelineless (GLL) operations for both drilling and completion. The proposed tree is detailed in Figure 3.16.

The production control system will be E/H Multiplex (Mux) with flying lead connections between the tree and the electrical and hydraulic distribution manifold. The production control system will be operated from the production host via the electrical and hydraulic umbilical infrastructure. Back up contingency for power and signal will be inherent in the design to ensure dual redundancy for the controls. Remote vertical access to the control pod via a MODU or MSV will be assumed.

The flowlines will be designed to the maximum working and commissioning testing pressure of the system, however, during startup and shut down it is assumed that choking is required. ROV insert chokes (4" – 10K) are assumed for the base case design. MODU and/or MSV interface for recovery in a GLL will be the primary method of remediation and intervention. The chokes are to be operated via the E/H (Mux) production control and will not be required to be functional via the workover control system. All control line tubing on the tree will be fully welded to reduce leak paths.

All tree valves and stab seals in the system should be designed using metal to metal seals with resilient backup. Testing of all seals and valves will be required prior to installation. All valves will incorporate a metal to metal floating gate design with resilient (non-metallic) single stem seal. No backseat will be required on the valves. With reference to Figure 3.17, the hydraulic valves will be used as shown and should be designed for full 4,000 psi control system pressure actuation. The tree will have ROV override functionality for all valves with standard rotary type interfaces applied. Hot stabs will be used for direct access to test ports and pressure gauge packs.

The following illustration (Figure 3.17) is the Tree Process and Identification drawing for the tree pressure containing and pressure controlling interfaces.

Figure 3.16: Horizontal Tree - Tree Boundaries Bore Section

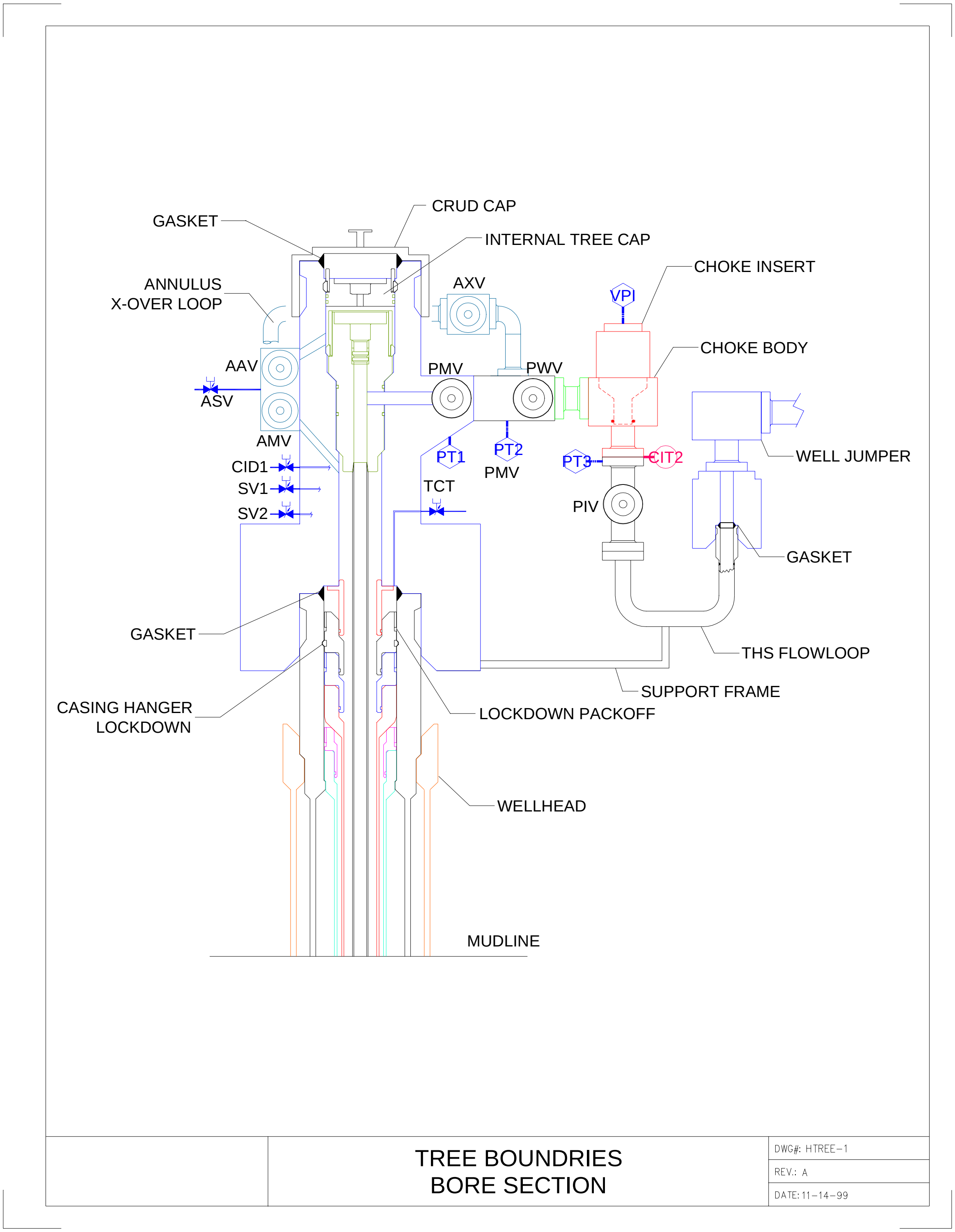
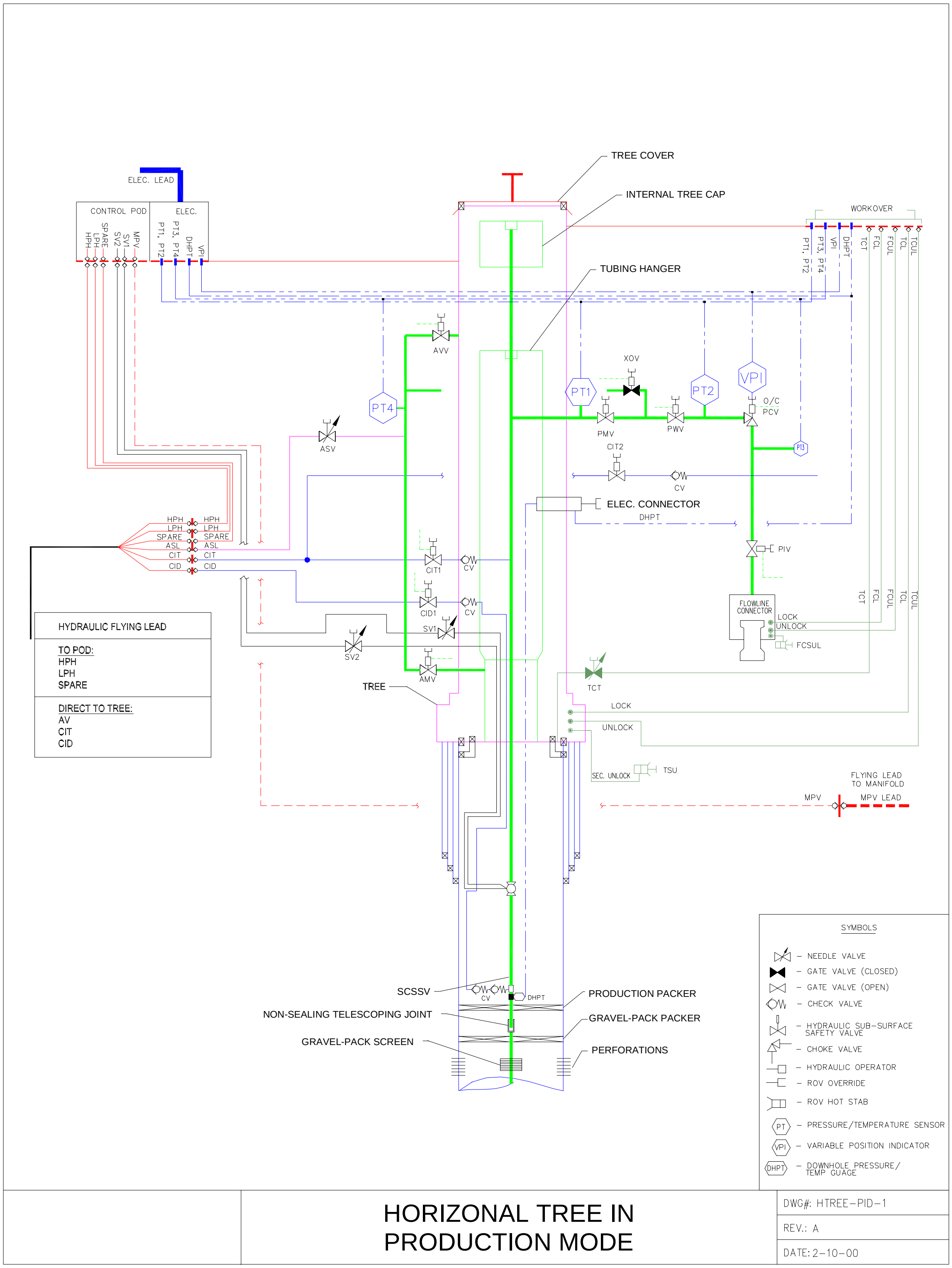


Figure 3.17: Horizontal Tree - Tree in Production Mode - Tree Cap Installed



3.4.4 Horizontal Tree Installation

Installation of the Horizontal Tree will consist of dual hydraulic umbilicals providing surface control of the TH landing string and safety tree and an external umbilical strapped to the drilling riser providing control for the horizontal tree valves. Selected functions such as tree connector (lock / unlock), flowline connector (lock / unlock) can be operated via either the umbilical or ROV high pressure intensifer skid packages.

Within the installation sequence, the tree will be installed at the onset of the completion operations and will provide an internal area for TH locking and sealing to the tree. Riser or premium tubing will be used to install the tree and allow direct high pressure access for installation of isolation plugs to be installed in the TH and Tree cap (if required).

3.4.4.1 Direct Hydraulic Workover Controls

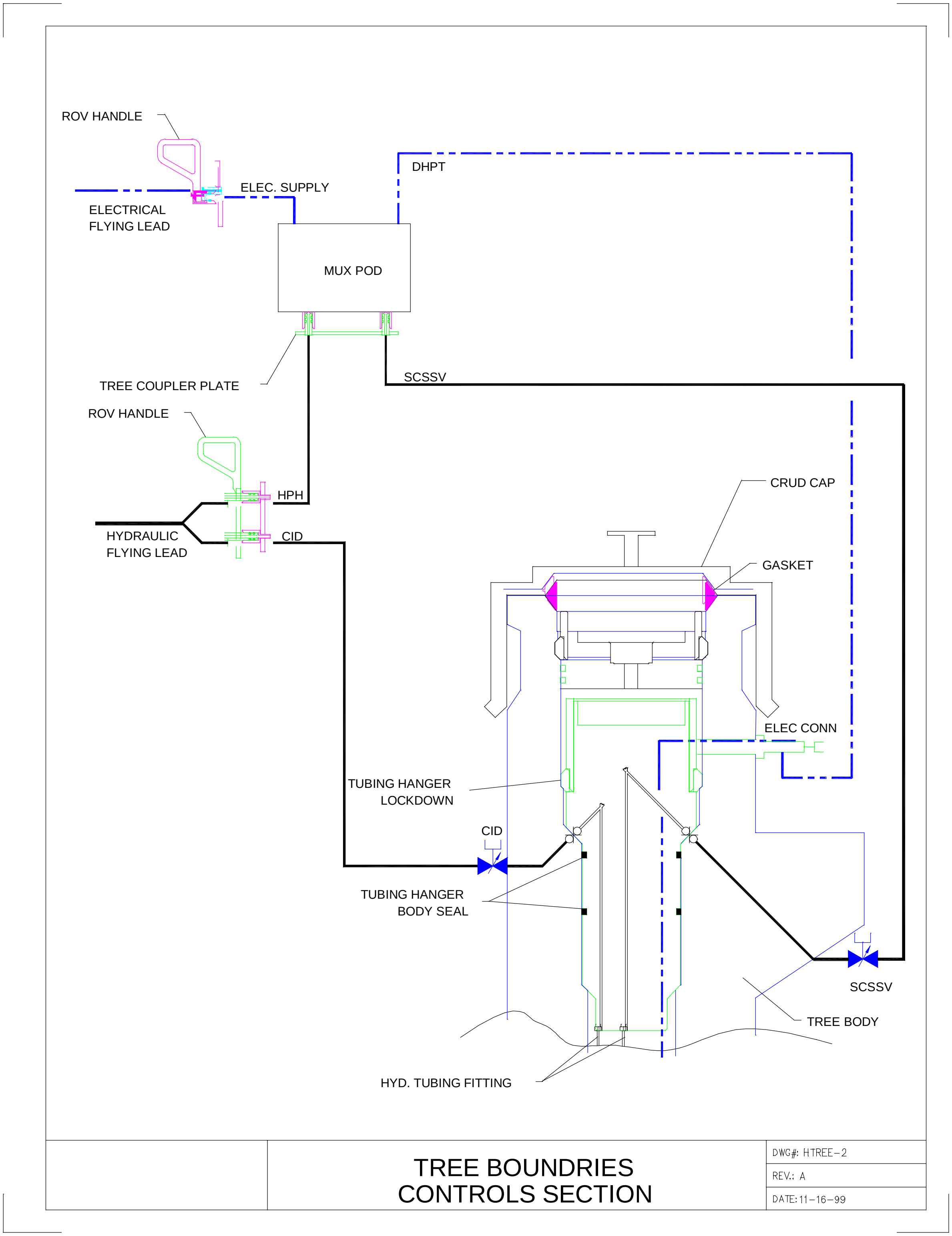
The direct hydraulic (DH) control system provides the hydraulic and electrical functions to install, and test the TH system, and conduct the tree operations during the workover phase. The workover riser will consist of a single production bore, premium tubing riser system with annulus circulation capability via the choke / kill lines. The TH and intelligent workover controls system (IWOCS) will allow rig interface control of the DH (SCSSV and CI lines) and operation of the hydraulic safety ball valve package (lower isolation, upper isolation valve, retainer and lubricator valves). Downhole chemical injection lines and SCSSV lines will penetrate through the TH system. The TH will be installed using a THRT and BOP spanner assembly to allow upper annular packoff using the BOP stack. The workover controls system will have a dedicated HPU located on the rig surface and will only be used for workover and intervention support function. This umbilical will be run internal to the 21” marine drilling riser and clamped onto the high pressure workstring.

During the workover mode, flying leads will establish both electrical and hydraulic communication to the tree pod. This feature eliminates a dedicated workover pod.

The horizontal tree valves will be controlled from a second umbilical which will be run outside the 21” marine drilling riser and will operate all tree circulation and isolation valves during the TH completion operations, installation of the wireline plugs and internal tree caps. The umbilical also controls the test tree functions of the system during the TH installation.

The proposed configuration is detailed in Figure 3.18.

Figure 3.18: Horizontal Tree - Tree Completion – Workover Mode



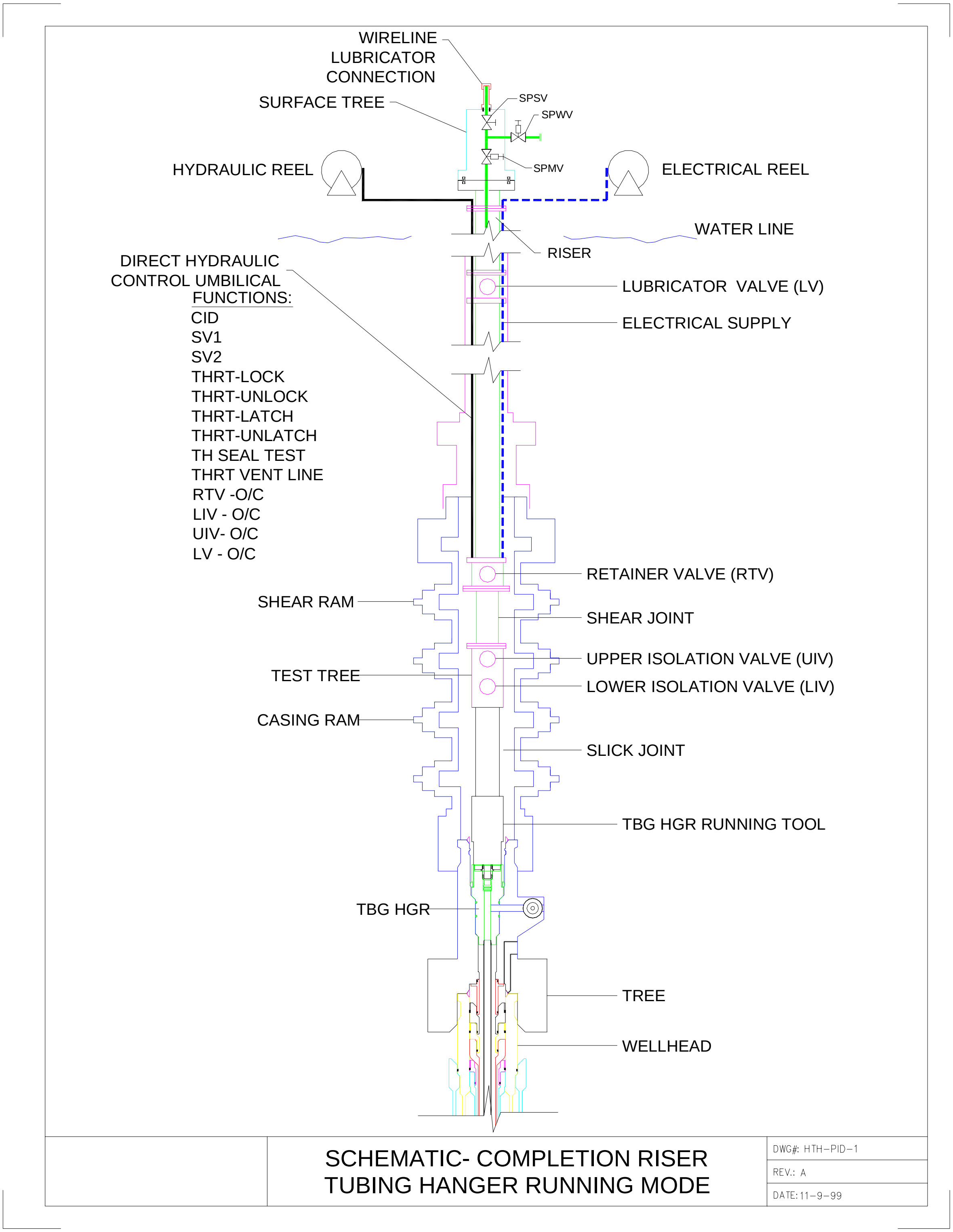
3.4.5 Installation and Workover System – Tubing Hanger Mode

The horizontal tree TH suspension system has been configured for both 4,000 and 6,000 feet with operations being conducted from a moored semisubmersible (MODU). The landing string used to install the TH and operation the installation package will provide direct rig based control and continuity to the tubing string. A safety tree system will isolate the well during the unloading mode and will provide a means for the BOP ram with casing element to seal to the TH landing string. Additionally, a shear joint will provide emergency well control with the blind shear ram.

Single bore tubing workover riser can be used as a landing string for installation of the TH and downhole completion. High pressure, premium metal to metal connections will be utilized for increased reliability during TH installation and well testing through the 21” Marine Drilling riser. The riser internal diameter will drift the internal production and tree cap isolation plugs. The riser will interface with the internal ball valve isolation package which will be run during the TH installation and well testing modes.

The tubing hanger and umbilical workover system are detailed in Figure 3.19.

Figure 3.19: Horizontal Tree - Completion Riser – Tubing Hanger Mode



3.4.6 Tree Cap

The horizontal tree will contain a primary wireline installed insert plug located in the production bore of the TH as the primary barrier to production. A secondary barrier will be installed internally within the marine drilling riser and will establish a secondary barrier to production. The secondary internal tree cap will engage in the upper section of the horizontal tree and can be tested via the annulus circulation loop. After recovery of the BOP's and riser an external protective cap will be installed over the well to reduce the ingress of debris.

3.5 General Assumptions

<u>Rig / MODU: (Mobile Offshore Drilling Unit):</u>

Installation is assumed to be by moored semisubmersible for both the 4,000 and 6,000 foot water depth applications. The rig would be positioned over an existing 6 well cluster allowing mobility between wells in the field without additional mooring cost. The wells will be drilled with a standard BOP system (18 ¾" –10M) with 21" Drilling riser system. MODU will be assumed to provide adequate deployment and recovery capability for the trees, tubing head spools, and manifolds to be tested off the critical path of operations.

<u>Guidelines Drilling and Completion Operations:</u>

The design and sequence of operations will assume that the BOP stack allows funnel down reentry on the wellhead with funnel up system of reentry on the tubing head spool. The BOP stack would be required to accommodate a remote releasable funnel system. Deployment of open water equipment (trees, THS, jumpers, etc.) would be executed off the field location and the rig would be repositioned for final landing.

<u>Metocean/Environmental:</u>

The basis for the design will be typical GoM weather, and current predictions for the installation, workover and remediation activities.

<u>Wellhead / Field Assumptions</u>:

A conventional shallow water flow wellhead design will be used for soft soil conditions which affords adequate bending rigidity for moored applications and the associated flowline / umbilical loads. The wellhead will interface with the THS via a conventional lockdown assembly that will lock the production casings strings in the wellhead. The manifold would be positioned within 100+/- feet of the wellhead cluster. The wellhead site should not have evidence of shallow water flow or seafloor anomalies that would pose a risk to the installation and field production life.

<u>Specification / Codes and Standards</u>:

Assumption for the operations will be conventional US Minerals Management Service (MMS) Drilling and Completion Regulations with subsea equipment design in accordance with API (17D, 17H, 14D.)

4 FAILURE MODE AND EFFECT ANALYSIS

4.1 Definition

A failure mode and effects analysis (FMEA) involves a systematic review of subsystems to identify critical failures, including the causes and effects of such failures. A team of engineers from the JIP team has performed an FMEA of the subsea systems listed below and have identified potential single point failures and effects. The review was recorded on worksheets, which are presented as Appendix I of this report. Appendix II contains diagrams that detail the failure modes identified for subsystems 1 through 6 above.

The systems reviewed were:

1. Downhole Completion Boundaries
2. Tree / Wellhead Interface Boundaries
3. Well Jumper System
4. Hydraulic and Electrical System
5. Manifold System
6. Flowline System
7. Conventional Tree Tuning Hanger Installation Mode
8. Conventional Tree Workover Mode
9. Horizontal Tree Installation Mode

For each component within a subsystem the failure modes and their effects on the rest of the system were evaluated and recorded on the FMEA worksheets.

Each subsystem was systematically reviewed by identifying components and applying the following questions:

- How can each part conceivably fail?
- What mechanisms might produce these modes of failure?
- What could the effects be if the failures did occur?
- Is the failure in the safe or unsafe direction?
- How is the failure detected?
- What inherent provisions are provided in the design to compensate for the failure?
- What is the frequency and consequence severity associated with each failure?

4.2 Objectives of FMEA

The objectives of the failure mode and effects analysis were as follows:

- Identify conceivable failures and their effects on operational success of the system.
- List potential failures, and identify the magnitude of their effects.
- Provide basis for establishing corrective action priorities.
- Provide historical documentation for future reference to aid in analysis of field failures and consideration of design changes.

4.3 Methodology

The analysis has been performed according to the following scheme:

- Definition of the main functions of the subsea system.
- Subsea System breakdown into subsystems.
- Identification of failures and their effects (recorded on FMEA worksheets).

4.4 Identification of Failure Modes and Effects

The FMEA team reviewed the subsystems in order to identify potential failures and their effects. The findings of the team were recorded on FMEA worksheets.

The various entries in the FMEA worksheet are best illustrated by going through a specific worksheet column by column. This study has used the FMEA worksheet format presented in Figure 4.1.

4.4.1 FMEA Worksheet Headings

System: The system being analyzed is identified in bold print at the top of each page.

4.4.2 FMEA Worksheet Columns

Component Name: The component that is being analyzed.

Ref #: The number/letter for the line of the FMEA.

Function: The function of the component.

Operation Mode (Op Mode): The mode of operation that the system is in when the component is analyzed (I = installation, NP = normal production, WO = workover).

Failure Mode: For each component's function and operational mode, failure modes are identified and recorded. A failure mode is defined as the manner by which a failure is revealed (i.e., failure of a valve to open on demand). All units are designed to fulfill one or more functions; a failure is thus defined as non-fulfillment of one or more of these functions.

Failure Cause: The possible failure mechanisms (corrosion, erosion, fatigue, etc.) that may produce the identified failure modes were recorded.

Local Effect: The main effects of the identified failure modes on the subsystem are recorded.

End Effect: The main effects of the identified failure modes on the primary function of the system and the resulting operational status of the system after the failure are recorded.

Detection Method: The various possibilities for detection of the identified failure modes are then recorded. These may involve different alarms, testing, human perception, and so on. Some failures are called *evident failures*. Evident failures are detected instantly. Another type of failures is called the *hidden failure*. A hidden failure is normally detected only during testing of the unit. The failure mode "fail to start" of a pump with operational mode "standby" is an example of a hidden failure.

Compensating Provision: Possible actions to maintain operability (if possible), correct the failure, and/or restore the function or prevent serious consequences are then recorded. Actions that are likely to reduce the frequency of the failure modes are also recorded.

Remarks: Additional remarks that are relevant to the failure mode identified.

Figure 4.1: FMEA Worksheet

SYSTEM NAME

Component Name	Ref	Function	Op Mode	Failure Mode	Failure Cause	Local Effect	End Effect	Detection Method	Compensating Provision	Remarks

5 SUBSEA SYSTEM OPERATIONAL PROCEDURES

5.1 Introduction

The Phase I of the Dry Tree Tieback Alternatives Study (DTTAS)[1] developed Capital costs (CAPEX) and Operational costs (OPEX) for the Tubing Riser, Single Casing Riser and Dual Casing Riser completions to SPARS and TLP's. The Phase II Study of the DTTAS evaluated the relative safety of the three "dry tree" systems to provide risk-adjusted life cycle costs. The primary objective and most significant aspect of the Phase II DTTAS, was the demonstration of a method for determining Risk costs (RISKEX) for dry well systems.

This Subsea JIP study extends the DTTAS to include subsea wells and expands the scope to include Reliability, Availability and Maintainability costs (RAMEX). RAMEX accounts for repair costs and the value of lost production that result from zone depletions and system failures.

Operational procedures developed in Phase I and Phase II DTTAS have been used as a basis for the OPEX, RISKEX and RAMEX determinations in this Subsea JIP study. The operational procedures are arranged in steps that correspond to well control barrier changes to facilitate RISKEX calculations. Risk of loss of well control is negligible during the initial subsea installation until the pre-drilled wells are perforated and has therefore not been considered.

Rig or service vessel spread costs for initial subsea installations (including well completions) are included in the CAPEX. Note that this approach is different in the DTTAS where initial installation of the wells and subsequent repairs of wells are included in the OPEX. Operating costs for operating personnel, facilities maintenance, transportation and other field operating expenses are not considered in this study but must be appropriately included in a complete project economics evaluation.

5.2 Design Basis Assumptions

The operational procedures are based on the same assumptions that were used for the DTTAS as follows:

1. The drilling vessel will pre-drill all wells and install temporary abandonment plugs to secure each well before the subsea BOP stack is removed.[2] The drilling vessel will also install a subsea tubing-spool on each well with appropriate flowline connection to facilitate later flowline and umbilical installations.

2. The subsea facilities are installed and the wells are "batch-completed" after all wells are drilled. Completion of the Frac-Packed wells involves the installation of the Frac-Pack system with a gravel-pack packer (or isolation packer) and associated seal bore in which to stab a seal assembly. Horizontal lateral

[1] R. Goldsmith, R. Eriksen, F. J. Deegan, "Lifetime Risk-Adjusted Cost Comparison for Deepwater Well Riser Systems" presented at OTC in Houston May 1999 (OTC 10976.

[2] Pre-drilling all wells corresponds to the design basis of the DTTAS. The subsequent installation of the subsea systems and the well completion operations correspond to the installation of risers and well completions for the DTTAS.

completions involve drilling the horizontal lateral out of 9 5/8 inch casing, installation of a 7 inch pre-packed screen liner with an isolation packer with associated seal bore above the liner top in which to stab a seal assembly. For both frac-packed and horizontal lateral completed wells, the completion string is run in one operation to prevent the need for downhole connections to deep-set chemical injection ports and pressure / temperature sensors.

3. The production intervals are at the same depth below mudline (10000 feet) for both water depths. Both the time to run or pull equipment from the sea floor and the time to trip in the hole to total depth are a function of water depth.
4. These procedures are applicable for both conventional and horizontal trees.

5.3 Operations Required for Total Field-Life Development

Table 5.1 lists the operational procedures that were developed in the DTTAS to define various field development scenarios. The time required for each operational step is estimated for 4000 feet and 6000 feet water depth. These "step times" are the exposure time for each operational configuration of well components that comprise the well control barriers.

Table 5.1: Projected Accounting of Operations for Full Field Life Development – Base Case from DTTAS

Initial Installations, Workovers and Maintenance Operations Based on 10 year producing life.	Number Required 12 well case	 6 well case
Initial Installation of Frac-Pack Completion System	6	3
Initial Installation of Horizontal Lateral-Screen Completion	6	3
Pull Completion, Install New Frac-Pack Completion	5	3
Pull Completion, Plug Lower Zone and Install Uphole Frac-Pack Recompletion	4	2
Pull Completion, Plug Lower Zone, Sidetrack and Recomplete with Frac-Pack	4	2
Pull Completion, Plug Lower Zone, Sidetrack and Recomplete Horizontal Well	5	2
Repair Completion System Leaks	2	1
Wireline maintenance - Cutting paraffin, surveys, etc. (once per month per well)	1440	720
Coiled Tubing Operations – Downhole repairs, etc. (twice per year per well)	240	120

The number of wireline maintenance and coiled tubing operations in Table 5.1 was considered typical for Gulf of Mexico platform completions when the DTTAS was developed. These operations were common between all alternatives of the DTTAS and were therefore excluded from the original DTTAS operational procedures.

For subsea operations these wireline / coiled tubing operations require significant expenditures for vessel spread costs (MSV, Rig, etc.). In addition, production may be shut-in for several months waiting on the required resource to be available. Therefore, subsea wells are equipped with paraffin inhibitor injection systems and permanent downhole pressure sensors are used.

The cost of paraffin inhibitor chemical for subsea wells and the cost of wireline and coiled tubing operations on dry tree wells are assumed equivalent and therefore are excluded in the comparison of the systems.

Table 5.2 lists the operational procedures that have been developed for this Subsea JIP study. The number of required operations listed in the table provide a base case for comparison with the DTTAS. The number of each type of operations to use for a site-specific study depends on several factors. The majority of re-completions are typically required because of zonal depletion; the wells are re-completed to new zones when production declines below an economic limit. These re-completions are termed "planned" in this study because the operations can be planned and scheduled while the well is still producing. The spreadsheet program permits the user to easily develop the number and time schedule for planned re-completions based on site-specific reservoir projections such as recoverable hydrocarbons, initial production rates and production decline rates.

Unplanned re-completions / workovers are more typically required as a result of a completion component failure such as a sand control failure, a system leak or a component function failure. The number of unplanned re-completions for a site-specific study are calculated by the spreadsheet program based on individual completion component reliabilities.

Table 5.2: Projected Accounting of *Planned* Operations for Full Field Life Development – Base Case for This Study

Initial Installations and Planned Intervention Operations Based on 10 year producing life.	Estimated Number Required 12 well case*	 6 well case
Initial Installation of Subsea System (Flowlines, PLEM, UTS, Umbilicals, etc.)	2 systems	1 system
Initial Installation of Frac-Pack Completion System	6	3
Initial Installation of Horizontal Lateral-Screen Completion	6	3
Pull Completion, Plug Lower Zone and Install Uphole Frac-Pack Recompletion	4	2
Pull Completion, Plug Lower Zone, Sidetrack and Recomplete with Frac-Pack	4	2
Pull Completion, Plug Lower Zone, Sidetrack and Recomplete Horizontal Well	5	2

* The Base Case for this study is a 6 well subsea system. The 12 well case is two 6 well cases and is shown for comparison with the 12 well DTTAS cases. Note that only planned interventions are listed in this table.

Table 5.3 lists case example default values of spread costs for the various vessels used for the installation and repair operations. The spreadsheet program permits the user to select other values.

Table 5.3: Spread Cost for Installation and Repair Vessels – Base Case for This Study

Repair Resource	Availability Time, days	Spread Cost $/day
Rig (MODU 8 point spread moored)	120	$240,000
Pipeline Installation Vessel (DP, heavy lift capability, etc.)	60	$340,000
Umbilical Installation Vessel	30	$200,000
MSV Spread (With capability to support lightweight packages)	7	$60,000
DSV Spread (ROV only – monitor and visual checks)	5	$30,000
TLP or SPAR Platform Rig	30	$120,000
Wireline or Coiled Tubing Unit	2	$25,000

As a demonstration of this base case example, Table 5.4 lists the non-discounted OPEX for all installation and planned re-completions operations in Table 5.1. These OPEX values are based on the assumed vessel spread cost (Table 5.3) and re-completion frequencies (total number of operations of each type during the total field life) that are listed in Table 5.2.

The "Total OPEX" for all operations includes the OPEX for all operations of all types during the ten years of operation. For example, the 6 well subsea system includes:

- Initial installation of flowlines, manifold, hydraulic and electrical umbilicals, flying leads, control umbilicals,
- 6 initial well (completion) installations,
- the 10 other major workover rig operations and
- all the subsea system repair operations (listed in Table 5.6) that are predicted during the field-life and ten years of production.

Total field life operating cost, OPEX, are calculated as the total of the vessel operating hours for the individual operations times the number of operations during the total field life times the rig spread cost. The operating hours for the individual operations are derived from the detailed procedures documented in Section 5.

Table 5.4: Summary Table of Rig Operating Hours for Installation and Re-completion Operations for a 6-Well Dry Tree Tieback Systems

TLP Operations, 6 Wells		**Workover Rig Hours for Each Type of Operation**					
	Field Life	**1-pipe (TR)**		**2-pipe (SC)**		**3-pipe (DC)**	
Type of Operations	**Number of**	**Water Depth, feet**		**Water Depth, feet**		**Water Depth, feet**	
	Operations	**4000**	**6000**	**4000**	**6000**	**4000**	**6000**
Initial Installation - Frac Pack	3	371	410	287	312	347	390
Initial Installation - Horizontal	3	527	566	443	468	503	546
Workover – Uphole Frac Pack	2	440	488	234	237	234	237
Workover – Sidetrack, Frac Pack	2	822	870	616	619	616	619
Workover – Sidetrack, Horizontal	2	764	812	558	561	558	561
Total Rig Hours for All Operations		6746	7268	5006	5174	5366	5642
Total Rig Days for All Operations		**281**	**303**	**209**	**216**	**224**	**235**
Million Dollars OPEX (non-discounted)		**33.7**	**36.3**	**25.0**	**25.9**	**26.8**	**28.2**
SPAR Operations, 6 Wells		**Workover Rig Hours for Each Type of Operation**					
	Field Life	**1-pipe (TR)**		**2-pipe (SC)**		**3-pipe (DC)**	
Type of Operations	**Number of**	**Water Depth, feet**		**Water Depth, feet**		**Water Depth, feet**	
	Operations	**4000**	**6000**	**4000**	**6000**	**4000**	**6000**
Initial Installation - Frac Pack	3	364	404	275	300	331	374
Initial Installation - Horizontal	3	520	560	431	456	487	530
Workover – Uphole Frac Pack	2	413	460	224	227	224	227
Workover – Sidetrack, Frac Pack	2	795	842	606	609	606	609
Workover – Sidetrack, Horizontal	2	737	784	548	551	548	551
Total Rig Hours for All Operations		6542	7064	4874	5042	5210	5486
Total Rig Days for All Operations		**273**	**294**	**203**	**210**	**217**	**229**
Million Dollars OPEX (non-discounted)		**32.7**	**35.3**	**24.4**	**25.2**	**26.1**	**27.4**

Table 5.5: Summary Table of Rig Operating Hours for Installation and Re-completion Operations for a 6-well Subsea Tieback System

Subsea, 6 Wells		Workover Rig Hours for Each Type of Operation			
	Field Life	Conventional		Horizontal	
Type of Operations	**Number of**	**Water Depth, feet**		**Water Depth, feet**	
	Operations	**4000**	**6000**	**4000**	**6000**
Initial Installation - Frac Pack	3	862	1002	836	961
Initial Installation - Horizontal	3	884	1016	858	975
Workover - Uphole Frac Pack	2	1010	1198	785	905
Workover - Sidetrack, Frac Pack	2	1382	1570	1227	1347
Workover - Sidetrack, Horizontal	2	1315	1514	1019	1131
Total Rig Hours for All Operations		12652	14618	11144	12574
Total Rig Days for All Operations		**527**	**609**	**464**	**524**
Million Dollars OPEX (non-discounted)		**126.5**	**146.2**	**111.4**	**125.7**

The cost of lost production, represented by RAMEX, includes both the vessel operating time and the vessel availability time. Default values for vessel availability time are listed in Table 5.3. The spreadsheet program permits user defined values for these vessel availability times.

Table 5.6: Predicted Number of *Unplanned* Operations for Full Field Life Development – Base Case for This Study

Workovers and Subsea Intervention Operations Based on 10 year producing life.	Estimated Number Required 12 well case*	 6 well case
Repair Completion System Leaks	5	2.5
Repair / Replaced Subsea Tree	4	2
Coiled Tubing Operations – Downhole repairs, etc.	3	1.5
Repair / Replace Pipeline (frequency for 2 pipelines per 6 well system, 35 miles)	0.2	0.1
Repair Pipeline End Manifold (frequency for 2 PLEM per 6 well system)	0.4	0.2
Repair / Replace Flowline Jumper	1	0.5
Repair / Replace Hydraulic Umbilical (35 miles)	0.4	0.2
Repair / Replace Electrical Umbilical (35 miles)	0.4	0.2
Repair / Replace Well Control Pod (frequency for 12 / 6 wells)	5	2.5
Repair / Replace Well Subsea Choke (frequency for 12 / 6 wells)	6	3
Repair / Replace Well Flying Leads (frequency for 12 / 6 flying leads)	1.4	0.7
Wireline maintenance - Cutting paraffin, surveys, etc.	0	0

* The Base Case for this study is a 6-well subsea system. This 12 well case, is two daisy chained 6-well cases (5 mile infield extension) and is shown for comparison with the 12-well DTTAS cases.

5.4 Detailed Operating Procedures

1.

Conventional Subsea Tree Operations
Initial Installation - Frac Pack

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- The initial installation of the total subsea system is assumed to be performed in a continuous operation, including the installation of the pipeline end manifold, flowlines, individual well jumpers, individual well umbilicals and initial subsea well completions. The “Availability, Mobilization and Positioning/Mooring Time” for these operations involve only repositioning the installation vessel within the field.

Assumed Temporarily Abandoned Configuration of Well:

- A cement retainer and cement plug is at about 200 feet below subsea wellhead.
- A tubing head spool, for hanging the tubing string, is installed by the pre-drilling vessel.
- The tubing head spool provides a hub for attachment for well jumpers.
- A protector cap is installed over the subsea wellhead.

Procedure Step	**Operation Time, hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[232]** 36	**[275]** 48	**Step [0]** Not Applicable
2. Run well protector cap retrieving tool on a downline to retrieve the protector cap. Using ROV for guidance, latch protector cap. Unlatch protector cap with retrieving tool and retrieve to surface.	6	8	Not Applicable

3. Rig up to run riser and BOP's.	12	12	Not Applicable
4. Run Marine Riser and BOP.	45	65	Not Applicable
5. Test BOP's.	22	26	Not Applicable
6. Run bit and casing scraper, drill cement retainer and cement, go in hole to total depth; circulate and displace mud with seawater and, after cleaning the casing, displace seawater with filtered completion fluid. POOH.	39	44	Not Applicable
7. Rig up and run gauge ring, cement bond log, gamma ray, casing-collar locator, etc. (If squeeze cementing is required the drilling mud will be put back in the hole before cementing.) Set sump packer on workstring. Rig up separators, burner and associated equipment to flow and clean well.	72	72	Not Applicable
8. Pick up TCP guns and RIH. Pressure up annulus or drop bar to fire guns to perforate the well. Flow and clean well. POOH. TIH; circulate out fill.	**[320]** 72	**[347]** 80	**Add:** **Step (1)** Subsea BOP's and riser. (kill fluid is in)
9. Circulate in gel pill to control lost circulation, POOH.	12	12	
10. Pick up gravel pack tools including packer and RIH. (Screens , DH gauges, washpipe , etc.)	20	20	
11. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
12. Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool. Test BOP's.	24	28	

13. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger. Close SCSSV.	72	87	
14. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**<u>Add:</u>** **<u>Step (2)</u>** Tubing String, SCSSV, Packer, Subsea Tubing Hanger with Plugs
15. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	
16. Retrieve marine riser.	**[88]** 38	**[119]** 54	**<u>Remove:</u>** **<u>Step (3)</u>** Subsea BOP's and riser.
17. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
18. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Test SCSSV. Open SCSSV. Break glass plug in gravel pack packer. Rig up unloading equipment. Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well.	**[176]** 96	**[203]** 105	**<u>Add:</u>** **<u>Step (4)</u>** Subsea Tree **<u>Remove:</u>** Tubing hanger plug, Kill Weight Fluid
19. Release completion riser from subsea tree and pull completion riser.	26	38	
20. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.

Total Hours for This Procedure	**862**	**1002**	

2.

Conventional Subsea Tree Operations
Initial Installation - Horizontal Lateral Completion System

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- The initial installation of the total subsea system is assumed to be performed in a continuous operation, including the installation of the pipeline end manifold, flowlines, individual well jumpers, individual well umbilicals and initial subsea well completions. The “Availability, Mobilization and Positioning/Mooring Time” for these operations involve only repositioning the installation vessel within the field.

Assumed Temporarily Abandoned Configuration of Well:

- A cement retainer and cement plug is at about 200 feet below subsea wellhead.
- A tubing head spool, for hanging the tubing string, is installed by the pre-drilling vessel.
- The tubing head spool provides a hub for attachment for well jumpers.
- A protector cap is installed over the subsea wellhead.

Procedure Step	**Operation Time, hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[140]** 36	**[183]** 48	**Step [0]** Not Applicable
2. Run well protector cap retrieving tool on a downline to retrieve the protector cap. Using ROV for guidance, latch protector cap. Unlatch protector cap with retrieving tool and retrieve to surface.	6	8	Not Applicable

3.	Rig up to run riser and BOP's.	12	12	Not Applicable
4.	Run Marine Riser and BOP.	45	65	Not Applicable
5.	Test BOP's.	22	26	Not Applicable
6.	Run bit and casing scraper; drill cement retainer and cement. Go in hole to float and test casing.	19	24	
7.	Drill float, cement, casing shoe and 10 feet of new hole. Circulate and run leak off test. Squeeze if necessary to achieve adequate kick tolerance for drilling ahead.	**[434]** 10	**[453]** 10	**<u>Add:</u>** **<u>Step (1)</u>** Subsea BOP's and riser. (kill fluid is in)
8.	Run directional drilling BHA and build angle to horizontal. Drill 1500-foot lateral. Circulate slugs and backream as required to clean hole. POOH.	192	192	
9.	Pick up and run sand control screen into lateral. Circulated and condition hole; spot open hole completion fluid as required. Gravel pack liner. Set liner; set and test liner packer. Circulate in gel pill if required to control lost circulation. POOH.	126	126	
10.	Rig up permanent packer on workstring and set above top of liner.	10	10	
11.	Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool. Test BOP's.	24	28	

12.	Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger-running tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger. Close SCSSV. 24+4+35/50+2+4=69/84	72	87	
13.	Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**<u>Add:</u>** **<u>Step (2)</u>** Tubing String, SCSSV, Packer, Subsea Tubing Hanger with Plug
14.	Rig up to retrieve marine riser. Displace brine in riser with seawater.	18	18	
15.	Retrieve marine riser.	**[88]** 38	**[119]** 54	**<u>Remove:</u>** **<u>Step(3)</u>** Subsea BOP's and riser.
16.	Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection. +2+2+35/50+4+3=50/65	50	65	
17.	Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Test SCSSV. Open SCSSV. Break glass plug in gravel pack packer. Rig up unloading equipment. Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well. 2+4+4+2+6+48+24+4=96	**[176]** 96	**[203]** 105	**<u>Add:</u>** **<u>Step (4)</u>** Subsea Tree **<u>Remove:</u>** Tubing hanger plug, Kill Weight Fluid

18.	Release completion riser from subsea tree and pull completion riser.	26	38	
19.	Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.) 18/24+36=54/60	54	60	**Add:** Flowline jumper.
	Total Hours for This Procedure	**884**	**1016**	

3.

Conventional Subsea Tree Operations
Workover – Uphole Frac Pack

Resource Requirement
The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability
- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

Assumed Configuration of Well:
- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[106]** 48	**[136]** 60	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree.	36	54	Not Applicable

4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable
5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[162]** 28	**[213]** 40	**<u>Add:</u>** **<u>Step (1)</u>** Kill Weight Fluid Subsea Tubing Hanger Plugs **<u>Remove:</u>** Subsea Tree
6. Move tree to storage and maintenance location.	12	12	
7. Move BOP’s to moonpool and rig up to run marine riser.	12	12	
8. Run Marine Riser and BOP.	45	65	
9. Test BOP’s.	22	26	
10. Run completion riser and subsea tubing hanger-retrieving tool and latch the subsea tubing-hanger.	43	58	
11. Rig up lubricator and wireline unit and pull plug from the subsea tubing-hanger. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[78]** 6	**[88]** 6	**<u>Add:</u>** **<u>Step (2)</u>** Subsea BOP’s and riser **<u>Remove:</u>** Primary Barrier-Completion String
12. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	

13. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	48	58	
14. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
15. Pick up bit and scraper on drillstring and go in hole to plug-back total depth. Displace mud with seawater and seawater with filtered completion brine. POOH.	**[24]** 24	**[24]** 24	**<u>Add:</u>** **<u>Step (3)</u>** Cement Retainer and Cement **<u>Remove:</u>** Kill Weight Fluid (seawater in casing)
16. Run wireline logs to define zone for completion.	**[10]** 6	**[10]** 6	**<u>Add:</u>** **<u>Step (4)</u>** Kill Weight Fluid
17. Set sump packer for gravel pack.	4	4	
18. Pick up Tubing Conveyed Perforating, TCP, guns and retrievable packer and run in hole. Drop bar to perforate, flow and clean well. POOH. TIH; circulate out fill.	**[320]** 72	**[347]** 80	**<u>Add:</u>** **<u>Step (5)</u>** **<u>Remove:</u>** Cement Retainer and Cement
19. Circulate in gel pill to control lost circulation. Pull out of hole.	12	12	
20. Pick up gravel pack tools and go in hole.	20	20	
21. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
22. Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool. Test BOP's.	24	28	

23. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger. Close SCSSV.	72	87	
24. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**<u>Add:</u>** **<u>Step (6)</u>** Tubing String, SCSSV, Packer, Subsea Tubing Hanger with Plugs
25. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	
26. Retrieve marine riser.	**[88]** 38	**[119]** 54	**<u>Remove:</u>** **<u>Step (7)</u>** Subsea BOP's and riser.
27. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
28. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Test SCSSV. Open SCSSV. Break glass plug in gravel pack packer. Rig up unloading equipment. Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well.	**[176]** 96	**[203]** 105	**<u>Add:</u>** **<u>Step (8)</u>** Subsea Tree **<u>Remove:</u>** Tubing hanger plug, Kill Weight Fluid
29. Release completion riser from subsea tree and pull completion riser.	26	38	
30. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.

Total Hours for This Procedure	**1010**	**1198**	

4.

Conventional Subsea Tree Operations
Workover – Sidetrack, Frac Pack

<u>Resource Requirement</u>
The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

<u>Assumed Configuration of Well:</u>

- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[106]** 48	[**136]** 60	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree.	36	54	Not Applicable

4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable
5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[162]** 28	**[213]** 40	<u>**Add:**</u> <u>**Step (1)**</u> Kill Weight Fluid Subsea Tubing Hanger Plugs <u>**Remove:**</u> Subsea Tree
6. Move tree to storage and maintenance location.	12	12	
7. Move BOP's to moonpool and rig up to run marine riser.	12	12	
8. Run Marine Riser and BOP.	45	65	
9. Test BOP's.	22	26	
10. Run completion riser and subsea tubing hanger-retrieving tool and latch the subsea tubing-hanger.	43	58	
11. Rig up lubricator and wireline unit and pull plug from the subsea tubing-hanger. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[78]** 6	**[88]** 6	<u>**Add:**</u> <u>**Step (2)**</u> Subsea BOP's and riser <u>**Remove:**</u> Primary Barrier-Completion String
12. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	

13. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	48	58	
14. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
15. Run wireline logs to define zone for sidetracking.	**[8]** 8	**[8]** 8	**<u>Add:</u>** **<u>Step (3)</u>** Cement Retainer and Cement
16. Pick up section mill and RIH and mill window in casing.	**[718]** 48	**[745]** 48	**<u>Add:</u>** **<u>Step (4)</u>** **<u>Remove:</u>** Cement Retainer and Cement
17. Run open-ended drillstring to window. Run leak off test. Spot cement sidetrack plug. POOH.	16	16	
18. Run bit and drilling BHA; to test and polish off cement plug. Wait on cement and drill to sidetrack point. POOH.	36	36	
19. Pick up bit and directional drilling BHA and RIH. Condition mud, build angle and drill hole through pay zones. Condition and POOH.	120	120	
20. Rig up and run liner. Circulate, mix and pump cement. POOH with running string.	24	24	
21. Pick up bit and bottom hole assembly and trip in hole. Drill cement to liner top. Test and squeeze liner top if required. Run small bit, bottom hole assembly and drill string stinger and clean out liner to bottom. Circulate, test and squeeze liner as required. Displace mud with filtered completion brine. POOH.	144	144	
22. Run wireline logs to define zone for completion.	6	6	

23. Set sump packer for gravel pack.	4	4	
24. Pick up Tubing Conveyed Perforating, TCP, guns and retrievable packer and run in hole. Drop bar to perforate, flow and clean well. POOH. TIH; circulate out fill.	72	80	
25. Circulate in gel pill to control lost circulation. Pull out of hole.	12	12	
26. Pick up gravel pack tools and go in hole.	20	20	
27. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
28. Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool.	24	28	
29. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger.	72	87	
30. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**<u>Add:</u>** **<u>Step (5)</u>** Tubing String, Packer, Subsea Tubing Hanger with Plugs
31. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	

32. Retrieve marine riser.	**[88]** 38	**[119]** 54	**Remove:** **Step (6)** Subsea BOP's and riser.
33. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
34. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Test SCSSV. Open SCSSV. Break glass plug in gravel pack packer. Rig up unloading equipment. Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well.	**[176]** 96	**[203]** 105	**Add:** **Step (7)** Subsea Tree **Remove:** Tubing hanger plug, Kill Weight Fluid
35. Release completion riser from subsea tree and pull completion riser.	26	38	
36. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
Total Hours for This Procedure	**1382**	**1570**	

5.

Conventional Subsea Tree Operations
Workover – Sidetrack, Horizontal Lateral Completion

Resource Requirement
The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

Assumed Configuration of Well:

- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[106]** 48	**[136]** 60	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree.	36	54	Not Applicable

4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable
5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[162]** 28	**[213]** 40	<u>**Add:**</u> <u>**Step (1)**</u> Kill Weight Fluid Subsea Tubing Hanger Plugs <u>**Remove:**</u> Subsea Tree
6. Move tree to storage and maintenance location.	12	12	
7. Move BOP's to moonpool and rig up to run marine riser.	12	12	
8. Run Marine Riser and BOP.	45	65	
9. Test BOP's.	22	26	
10. Run completion riser and subsea tubing hanger retrieving-tool and latch the subsea tubing-hanger.	43	58	
11. Rig up lubricator and wireline unit and pull plug from the subsea tubing-hanger. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[78]** 6	**[88]** 6	<u>**Add:**</u> <u>**Step (2)**</u> Subsea BOP's and riser <u>**Remove:**</u> Primary Barrier-Completion String
12. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	

13. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	48	58	
14. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
15. Run wireline logs to define zone for sidetracking.	**[8]** 8	**[8]** 8	**<u>Add:</u>** **<u>Step (3)</u>** Cement Retainer and Cement
16. Pick up section mill and RIH and mill window in casing.	**[562]** 48	**[581]** 48	**<u>Add:</u>** **<u>Step (4)</u>** **<u>Remove:</u>** Cement Retainer and Cement
17. Run open-ended drillstring to window. Run leak off test. Spot cement sidetrack plug. POOH.	16	16	
18. Run bit and drilling BHA; to test and polish off cement plug. Wait on cement and drill to sidetrack point. POOH.	36	36	(sidetrack plug is not pressure barrier)
19. Pick up bit and directional drilling BHA and RIH. Condition mud for drilling horizontal hole. Build angle and drill horizontal lateral in producing zone. Circulate, backream and circulate slugs to condition lateral for completion. Spot completion fluid in open hole. POOH.	240	240	
20. Run screen into lateral. Circulate and condition hole; spot open hole completion fluid as required. Gravel pack liner. Set liner and pull out of hole.	126	126	
21. Rig up permanent packer on workstring and set above top of liner.	10	10	
22. Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool.	24	28	

23. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger.	72	87	
24. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**Add:** **Step (5)** Tubing String, Packer, Subsea Tubing Hanger with Plug
25. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	
26. Retrieve marine riser.	**[88]** 38	**[119]** 54	**Remove:** **Step (6)** Subsea BOP's and riser.
27. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
28. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Test SCSSV. Open SCSSV. Break glass plug in gravel pack packer. Rig up unloading equipment. Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well.	**[176]** 96	**[203]** 105	**Add:** **Step (7)** Subsea Tree **Remove:** Tubing hanger plug, Kill Weight Fluid
29. Release completion riser from subsea tree and pull completion riser.	26	38	
30. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
Total Hours for This Procedure	**1226**	**1406**	

6.

Conventional Subsea Tree Operations
Workover – New Frac Pack

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Workover for a New Frac-Pack is an "unplanned" operation caused by a Frac-Pack failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this time.

Assumed Configuration of Well:

- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time.	**[178]** 120	**[208]** 132	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree.	36	54	Not Applicable

4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable
5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[162]** 28	**[213]** 40	**<u>Add:</u>** **<u>Step (1)</u>** Kill Weight Fluid Subsea Tubing Hanger Plugs **<u>Remove:</u>** Subsea Tree
6. Move tree to storage and maintenance location.	12	12	
7. Move BOP's to moonpool and rig up to run marine riser.	12	12	
8. Run Marine Riser/BOP.	45	65	
9. Test BOP's.	22	26	
10. Run completion riser and subsea tubing hanger retrieving tool and latch the subsea-tubing hanger.	43	58	
11. Rig up lubricator and wireline unit and pull plug from the subsea tubing hanger. Work tubing from packer to circulate kill weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[496]** 6	**[533]** 6	**<u>Add:</u>** **<u>Step (2)</u>** Subsea BOP's and riser **<u>Remove:</u>** Tubing hanger plug Primary Barrier - Completion String
12. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	

13. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	48	58	
14. Run wear bushing on workstring and set in subsea wellhead.	12	12	
15. Pick up mill to mill gravel pack packer and RIH. Mill over packer and retrieve if possible. Wash gravel from hole; fish screen and other tools from hole. Circulate hole clean and POOH. [3]	48	48	
16. Rig up and run gauge ring, cement bond log, gamma ray, casing collar locator, etc. Run casing caliper log to confirm riser integrity.	12	12	
17. Pick up bit and scraper on drillstring and go in hole to plug-back total depth. Displace mud with filtered completion brine. POOH.	24	24	
18. Rig up wireline unit and set sump packer. (Log and Tie-in on depth.)	18	18	
19. Pick up Tubing Conveyed Perforating, TCP, guns and retrievable packer and run in hole. Drop bar to perforate, flow and clean well. POOH. TIH; circulate out fill.	72	80	
20. Circulate in gel pill to control lost circulation, POOH.	12	12	
21. Pick up gravel pack tools including packer and RIH.	20	20	
22. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	

[3] It may be more desirable to "Plug Lower Zone, Sidetrack and Recomplete with Frac-Pack". A sidetrack and recompletion operation would be more expensive but would provide a new completion in an undamaged zone for better productivity.

23. Run workstring with wear bushing retrieving tool to retrieve wear bushing from subsea tubing spool. Test BOP's.	24	28	
24. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger. Close SCSSV.	72	87	
25. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	<u>**Add:**</u> <u>**Step (3)**</u> Tubing String, SCSSV, Packer, Subsea Tubing Hanger with Plugs
26. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	
27. Retrieve marine riser.	**[88]** 38	**[119]** 54	<u>**Remove:**</u> <u>**Step (4)**</u> Subsea BOP's and riser.
28. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
29. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Open SCSSV. Break glass plug in gravel pack packer. Swab well in (or jet in with coiled tubing and nitrogen.) Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well. (This may be longer pending the rig up time for unloading equipment – expect 60 – 72 hours)	**[176]** 96	**[203]** 105	<u>**Add:**</u> <u>**Step (5)**</u> Subsea Tree <u>**Remove:**</u> Tubing hanger plug, Kill Weight Fluid
30. Release completion riser from subsea tree and pull completion riser.	26	38	
31. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	<u>**Add:**</u> Flowline flying leads.

Total Hours for This Procedure	**1146**	**1334**	

7.

Conventional Subsea Tree Operations
Repair Completion System Leak

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Repair Completion System Leak is "unplanned" operation caused by a tubing string component failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this time.

Assumed Configuration of Well:

- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time.	**[178]** 120	**[208]** 132	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree,	36	54	Not Applicable
4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit open and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable

5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[162]** 28	**[213]** 40	**<u>Add:</u>** **<u>Step (1)</u>** Kill Weight Fluid Subsea Tubing Hanger Plugs **<u>Remove:</u>** Subsea Tree
6. Move tree to storage and maintenance location.	12	12	
7. Move BOP's to moonpool and rig up to run marine riser.	12	12	
8. Run Marine Riser/BOP.	45	65	
9. Test BOP's.	22	26	
10. Run completion riser and subsea tubing hanger retrieving tool and latch the subsea-tubing hanger.	43	58	
11. Rig up lubricator and wireline unit and pull plug from the subsea tubing hanger. Work tubing from packer to circulate kill weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[134]** 6	**[159]** 6	**<u>Add:</u>** **<u>Step (2)</u>** Subsea BOP's and riser **<u>Remove:</u>** Tubing hanger plug Primary Barrier - Completion String
12. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	
13. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	48	58	

14. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running tool on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Pick up out of packer and circulate heavy kill fluid into tubing followed by seawater to fill tubing from vessel to seafloor. Monitor well for 30 minutes to ensure that well is controlled by heavy kill fluid in combination with seawater from seafloor to surface. Hang tubing in subsea tubing hanger.	72	87	
15. Rig up wireline unit and set plug in subsea tubing hanger. Release and retrieve completion riser.	**[46]** 28	**[58]** 40	**Add:** **Step (3)** Tubing String, Packer, Subsea Tubing Hanger with Plugs
16. Rig up to retrieve riser. Displace brine in riser with seawater.	18	18	
17. Retrieve marine riser.	**[88]** 38	**[119]** 54	**Remove:** **Step (4)** Subsea BOP's and riser.
18. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
19. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Open SCSSV. Break glass plug in gravel pack packer. Swab well in (or jet in with coiled tubing and nitrogen.) Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well. (This may be longer pending the rig up time for unloading equipment – expect 60 – 72 hours)	**[176]** 96	**[203]** 105	**Add:** **Step (5)** Subsea Tree **Remove:** Tubing hanger plug, Kill Weight Fluid

20. Release completion riser from subsea tree and pull completion riser.	26	38	
21. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline flying leads.
Total Hours for This Procedure	**784**	**960**	

8.

Conventional Subsea Tree Operations
Repair / Replace Subsea Tree

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Repair / Replace Subsea Tree is an "unplanned" operation caused by a tree component failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this time.

<u>Assumed Configuration of Well:</u>

- In the production mode the wellhead connectors attach subsea wellhead housing to the tubing spool and the tubing spool to the subsea tree.

Procedure Step	**Oprn. Time hours**		**Component add / remove**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time.	**[178]** 120	**[208]** 132	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree,	36	54	Not Applicable
4. Kill well by bullheading tubing with kill weight fluid. Pump seawater to fill tubing from vessel to seafloor (tubing volume to seafloor). Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid in wellbore in combination with seawater from seafloor to surface. Rig up wireline unit and set plug in subsea tubing hanger. Rig down wireline unit, lubricator and surface tree.	12	12	Not Applicable

5. Actuate controls to disconnect subsea tree from tubing spool. Pull completion riser and tree.	**[90]** 28	**[117]** 40	**<u>Add:</u>** **<u>Step (1)</u>** Kill Weight Fluid, Subsea Tubing Hanger Plugs **<u>Remove:</u>** Subsea Tree
6. Move tree to storage and maintenance location. Repair or replace tree.	12	12	
7. Move subsea tree to moonpool. Run completion riser and connect riser connector to subsea tree. Run completion riser and subsea tree. Space out and, using ROV for guidance, connect subsea tree to tubing spool. Pressure test tree connection.	50	65	
8. Rig up lubricator and wireline unit and retrieve plug from subsea tubing spool. Open SCSSV. Break glass plug in gravel pack packer. Swab well in (or jet in with coiled tubing and nitrogen.) Unload well to rig to flow, clean and test. Close subsea valves and SCSSV to secure well.	**[176]** 96	**[203]** 105	**<u>Add:</u>** **<u>Step (2)</u>** Subsea Tree **<u>Remove:</u>** Tubing hanger plug, Kill Weight Fluid
9. Release completion riser from subsea tree and pull completion riser.	26	38	
10. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline flying leads.
Total Hours for This Procedure	**444**	**528**	

9.

Conventional Subsea Tree Operations
Coiled Tubing Downhole Repair

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Coiled Tubing Downhole Repair is an "unplanned" operation caused by a completion system failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this time.

Procedure Step	Oprn. Time hours		Component add / remove
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time.	**[178]** 120	**[208]** 132	**Step [0]** Not Applicable
2. Rig up to run completion riser.	10	10	Not Applicable
3. Run completion riser and, using ROV for guidance, position rig to latch subsea tree,	36	54	Not Applicable
4. Prepare well for coiled tubing operation. For example, kill well by bullheading tubing with kill weight fluid. Monitor well for 30 minutes to ensure that well is controlled by kill weight fluid.	12	12	Not Applicable

5. Rig up coiled tubing unit and perform coiled tubing maintenance or repair. An arbitrary time of 48 hours is allowed for performing the coiled tubing operation such as: plugging a depleted zone and opening and testing a new zone or acidizing a zone or installing an insert valve in a failed SCSSV. Rig down coiled tubing unit, lubricator and surface tree. (An arbitrary time of 24 hours has been allowed for performing the coiled tubing operation.)	**[60]** 60	**[60]** 60	**Add:** **Step (1)** Completion Riser and Surface Control Head, Kill Weight Fluid **Remove:** SCSSV, Subsea Tree
6. Release completion riser from subsea tree and pull completion riser.	**[26]** 26	**[38]** 38	**Add:** **Step (2)** SCSSV, Subsea Tree **Remove:** Completion Riser and Surface Control Head, Kill Weight Fluid
Total Hours for This Procedure	**264**	**306**	

10.

Horizontal Subsea Tree Operations
Initial Installation - Frac Pack

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- The initial installation of the total subsea system is assumed to be performed in a continuous operation, including the installation of the pipeline end manifold, flowlines, individual well jumpers, individual well umbilicals and initial subsea well completions. The "Availability, Mobilization and Positioning/Mooring Time" for these operations involve only repositioning the installation vessel within the field.

Assumed Temporarily Abandoned Configuration of Well:

- A cement retainer and cement plug is at about 200 feet below the subsea wellhead.
- Lockdown sleeve for 9 5/8 inch casing is installed by the pre-drilling vessel.
- A protector cap is installed over the subsea wellhead.

Procedure Step	**Operation Time, hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[252]** 36	**[299]** 48	**Step [0]** Not Applicable
2. Run well protector cap retrieving tool on a downline to retrieve the protector cap. Using ROV for guidance, latch protector cap. Unlatch protector cap with retrieving tool and retrieve to surface.	6	8	Not Applicable

3. Move horizontal tree to moonpool area, rig up and run tree on running string. Land and latch tree. Retrieve running string.	20	24	Not Applicable
4. Rig up to run riser and BOP's.	12	12	Not Applicable
5. Run Marine Riser and BOP.	45	65	Not Applicable
6. Test BOP's; install high pressure wear bushing.	22	26	Not Applicable
7. Run bit and casing scraper, drill cement retainer and cement, go in hole to total depth; circulate and displace mud with seawater and, after cleaning the casing, displace seawater with filtered completion fluid. POOH.	39	44	Not Applicable
8. Rig up and run gauge ring, cement bond log, gamma ray, casing-collar locator, etc. (If squeeze cementing is required the drilling mud will be put back in the hole before cementing.) Set sump packer on workstring. Rig up separators, burner and associated equipment to flow and clean well.	72	72	Not Applicable
9. Pick up TCP guns and retrievable packer and RIH. Pressure up annulus or drop bar to fire guns to perforate the well. Check for fill. Pull out of hole. Trip in hole to clean out fill.	**[344]** 72	**[371]** 80	<u>**Add:**</u> <u>**Step (1)**</u> Subsea BOP's and riser, subsea horizontal tree with high pressure wear bushing, kill fluid.
10. If required, circulate in gel pill to control lost circulation; POOH.	12	12	

11. Pick up gravel pack tools including packer and RIH. (Screens, DH gauges, washpipe, etc.)	20	20	
12. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
13. Run workstring with high pressure wear bushing retrieving tool to retrieve wear bushing from horizontal subsea tree. Test BOP's.	24	28	
14. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
15. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea test tree valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	<u>**Add:**</u> <u>**Step (2)**</u> Subsea tubing hanger, tubing string, packer, tubing riser, test tree, surface flowhead. <u>**Remove:**</u> Kill fluid, high pressure wear bushing.

16. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**<u>Add:</u>** **<u>Step (3)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** Tubing riser, test tree, surface flowhead.
17. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
18. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (4)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.
19. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.
Total Hours for This Procedure	**836**	**961**	

11.

Horizontal Subsea Tree Operations
Initial Installation - Horizontal Lateral Completion System

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- The initial installation of the total subsea system is assumed to be performed in a continuous operation, including the installation of the pipeline end manifold, flowlines, individual well jumpers, individual well umbilicals and initial subsea well completions. The "Availability, Mobilization and Positioning/Mooring Time" for these operations involve only repositioning the installation vessel within the field.

<u>Assumed Temporarily Abandoned Configuration of Well:</u>

- A cement retainer and cement plug is at about 200 feet below subsea wellhead.
- Lockdown sleeve for 9 5/8 inch casing is installed by the pre-drilling vessel.
- A protector cap is installed over the subsea wellhead.

Procedure Step	**Operation Time, hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time (First Initial Completion will require 72 hours mobilization/transit time, 48/60 hours for mooring operations. Succeeding operations only require repositioning of the vessel.)	**[160]** 36	**[207]** 48	**Step [0]** Not Applicable
2. Run well protector cap retrieving tool on a downline to retrieve the protector cap. Using ROV for guidance, latch protector cap. Unlatch protector cap with retrieving tool and retrieve to surface.	6	8	Not Applicable
3. Move horizontal tree to moonpool area, rig up and run tree on running string. Land and latch tree. Retrieve running string. 12+4/6+2/3+2/3 = 20/24	20	24	Not Applicable

4.	Rig up to run riser and BOP's.	12	12	Not Applicable
5.	Run Marine Riser and BOP.	45	65	Not Applicable
6.	Test BOP's; install high pressure wear bushing.	22	26	Not Applicable
7.	Run bit and casing scraper; drill cement retainer and cement. Go in hole to float and test casing.	19	24	Not Applicable
8.	Drill float, cement, casing shoe and 10 feet of new hole. Circulate and run leak off test. Squeeze if necessary to achieve adequate kick tolerance for drilling ahead.	**[458]** 10	**[477]** 10	**<u>Add:</u>** **<u>Step (1)</u>** Subsea BOP's and riser, subsea horizontal tree with high pressure wear bushing, kill fluid.
9.	Run directional drilling BHA and build angle to horizontal. Drill 1500-foot lateral. Circulate slugs and backream as required to clean hole. POOH.	192	192	
10.	Pick up and run sand control screen into lateral. Circulated and condition hole; spot open hole completion fluid as required. Gravel pack liner. Set liner; set and test liner packer. Circulate in gel pill if required to control lost circulation. POOH.	126	126	
11.	Rig up permanent packer on workstring and set above top of liner.	10	10	
12.	Run workstring with high pressure wear bushing retrieving tool to retrieve high pressure wear bushing from horizontal subsea tree. Test BOP's.	24	28	

13.	Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
14.	Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea test tree valves and SCSSV to secure well. Circulate kill fluid into landing string. 2+4+4+2+6+48+24+4 = 96	**[96]** 96	**[105]** 105	**<u>Add:</u>** **<u>Step (2)</u>** Subsea tubing hanger, tubing string, packer, tubing riser, test tree, surface flowhead. **<u>Remove:</u>** Kill fluid, high pressure wear bushing.
15.	Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**<u>Add:</u>** **<u>Step (3)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** Tubing riser, test tree, surface flowhead.
16.	Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
17.	Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (4)</u>** High pressure tree cap. **<u>Remove:</u>** Tubing hanger plug, Subsea BOP's and riser.

18.	Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
	Total Hours for This Procedure	**858**	**975**	

12.

Horizontal Subsea Tree Operations
Workover – Uphole Frac Pack

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

<u>Assumed Configuration of Well:</u>

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[127]** 48	**[163]** 60	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull protector cap with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable

5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**Add:** **Step (1)** Subsea BOP and riser. **Remove:** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[14]** 14	**[18]** 18	**Add:** **Step (2)** Worksting with wireline lubricator. **Remove:** Tubing hanger plug.
7. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.) Install high pressure wear bushing.	**[64]** 48	**[64]** 48	**Add:** **Step (3)** Kill weight fluid and high pressure wear bushing. **Remove:** Primary barrier-completion string and workstring with wireline lubricator.
8. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
9. Pick up bit and scraper on drillstring and go in hole to plug-back total depth. Displace mud with seawater and then displace seawater with filtered completion brine.	**[26]** 16	**[26]** 16	**Add:** **Step (4)** Cement Retainer and Cement
10. Run wireline logs to define zone for completion. Set sump packer for gravel pack.	10	10	
11. Pick up TCP guns and retrievable packer and RIH. Pressure up annulus or drop bar to fire guns to perforate the well. Check for fill. Pull out of hole. Trip in hole to clean out fill.	**[344]** 72	**[371]** 80	**Remove:** **Step (5)** Cement Retainer and Cement
12. If required, circulate in gel pill to control lost circulation; POOH.	12	12	

13. Pick up gravel pack tools including packer and RIH. (Screens, DH gauges, washpipe, etc.)	20	20	
14. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
15. Run workstring with high pressure wear bushing retrieving tool to retrieve wear bushing from horizontal subsea tree. Test BOP's.	24	28	
16. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
17. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	**Add:** **Step (6)** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **Remove:** Kill fluid and high pressure wear bushing.

18. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**<u>Add:</u>** **<u>Step (7)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** **Tubing riser,** test tree, surface flowhead.
19. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
20. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (8)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.
21. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.
Total Hours for This Procedure	**825**	**945**	

13.

Horizontal Subsea Tree Operations
Workover – Sidetrack, Frac Pack

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

Assumed Configuration of Well:

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	Oprn. Time hours		Component add / remove (for RISKEX calculations)
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[127]** 48	**[163]** 60	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull protector cap with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable

4. Test BOP's.	22	26	Not Applicable
5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**<u>Add:</u>** **<u>Step (1)</u>** Subsea BOP and riser. **<u>Remove:</u>** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[14]** 14	**[18]** 18	**<u>Add:</u>** **<u>Step (2)</u>** Worksting with wireline lubricator. **<u>Remove:</u>** Tubing hanger plug.
7. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	**[64]** 48	**[64]** 48	**<u>Add:</u>** **<u>Step (3)</u>** Kill weight fluid and high pressure wear bushing. **<u>Remove:</u>** Primary barrier-completion string, workstring and wireline lubricator.
8. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
9. Run wireline logs to define zone for sidetracking.	**[8]** 8	**[8]** 8	**<u>Add:</u>** **<u>Step (4)</u>** Cement Retainer and Cement
10. Pick up section mill and RIH and mill window in casing.	**[804]** 48	**[831]** 48	**<u>Remove:</u>** **<u>Step (5)</u>** Cement Retainer and Cement
11. Run open-ended drillstring to window. Run leak off test. Spot cement sidetrack plug. POOH.	16	16	

12. Run bit and drilling BHA; to test and polish off cement plug. Wait on cement and drill to sidetrack point. POOH.	36	36	(sidetrack plug is not pressure barrier)
13. Pick up bit and directional drilling BHA and RIH. Condition mud, build angle and drill hole through pay zones. Condition and POOH.	120	120	
14. Rig up and run liner. Circulate, mix and pump cement. POOH with running string.	24	24	
15. Pick up bit and bottom hole assembly and trip in hole. Drill cement to liner top. Test and squeeze liner top if required. Run small bit, bottom hole assembly and drill string stinger and clean out liner to bottom. Circulate, test and squeeze liner as required. Displace mud with filtered completion brine. POOH.	144	144	
16. Rig up and run gauge ring, cement bond log, gamma ray, casing-collar locator, etc. (If squeeze cementing is required the drilling mud will be put back in the hole before cementing.) Set sump packer on workstring. Rig up separators, burner and associated equipment to flow and clean well.	72	72	Not Applicable
17. Pick up TCP guns and retrievable packer and RIH. Pressure up annulus or drop bar to fire guns to perforate the well. Check for fill. Pull out of hole. Trip in hole to clean out fill.	72	80	
18. If required, circulate in gel pill to control lost circulation; POOH.	12	12	
19. Pick up gravel pack tools including packer and RIH. (Screens, DH gauges, washpipe, etc.)	20	20	
20. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
21. Run workstring with high pressure wear bushing retrieving tool to retrieve wear bushing from horizontal subsea tree. Test BOP's.	24	28	

22. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
23. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	**Add:** **Step (6)** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **Remove:** Kill fluid and high pressure wear bushing.
24. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**Add:** **Step (7)** Tubing hanger plug, SCSSV. **Remove:** **Tubing riser,** test tree, surface flowhead.
25. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
26. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**Add:** **Step (8)** High pressure tree cap. **Remove:** Subsea BOP's and riser.
27. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
Total Hours for This Procedure	**1267**	**1387**	

14.

Horizontal Subsea Tree Operations
Workover – Sidetrack, Horizontal Lateral Completion

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Workovers for Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal Lateral are assumed to be "planned" recompletions to new zones after the zones have depleted. Therefore, only minimal "Vessel Availability Time" is assumed for these operations.

Assumed Configuration of Well:

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[127]** 48	**[163]** 60	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull protector cap with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable

5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**Add:** **Step (1)** Subsea BOP and riser. **Remove:** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[14]** 14	**[18]** 18	**Add:** **Step (2)** Worksting with wireline lubricator. **Remove:** Tubing hanger plug.
7. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.) Install high pressure wear bushing.	**[64]** 48	**[64]** 48	**Add:** **Step (3)** Kill weight fluid and high pressure wear bushing. **Remove:** Primary barrier-completion string, workstring and wireline lubricator.
8. Pick up cement retainer and RIH. Set cement retainer above packer, squeeze cement below and spot cement above retainer. POOH.	16	16	
9. Run wireline logs to define zone for sidetracking.	**[8]** 8	**[8]** 8	**Add:** **Step (4)** Cement Retainer and Cement **Remove:**
10. Pick up section mill and RIH and mill window in casing.	**[596]** 48	**[615]** 48	**Add:** **Step (5)** **Remove:** Cement Retainer and Cement
11. Run open-ended drillstring to window. Run leak off test. Spot cement sidetrack plug. POOH.	16	16	

12. Run bit and drilling BHA; to test and polish off cement plug. Wait on cement and drill to sidetrack point. POOH.	36	36	(sidetrack plug is not pressure barrier)
13. Pick up bit and directional drilling BHA and RIH. Condition mud for drilling horizontal hole. Build angle and drill horizontal lateral in producing zone. Circulate, backream and circulate slugs to condition lateral for completion. Spot completion fluid in open hole. POOH.	240	240	
19. Pick up and run sand control screen into lateral. Circulated and condition hole; spot open hole completion fluid as required. Gravel pack liner. Set liner; set and test liner packer. Circulate in gel pill if required to control lost circulation. POOH.	126	126	
20. Rig up permanent packer on workstring and set above top of liner.	10	10	
21. Run workstring with high pressure wear bushing retrieving tool to retrieve high pressure wear bushing from horizontal subsea tree. Test BOP's.	24	28	
22. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
23. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string. 2+4+4+2+6+48+24+4 = 96	**[96]** 96	**[105]** 105	**<u>Add:</u>** **<u>Step (6)</u>** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **<u>Remove:</u>** Kill fluid and high pressure wear bushing.

24. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**Add:** **Step (7)** Tubing hanger plug, SCSSV. **Remove:** **Tubing riser,** test tree, surface flowhead.
25. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
26. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**Add:** **Step (8)** High pressure tree cap. **Remove:** Subsea BOP's and riser.
27. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
Total Hours for This Procedure	**1059**	**1171**	

15.

Horizontal Subsea Tree Operations
Workover – New Frac Pack

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Workover – New Frac Pack is an "unplanned" operation caused by a completion system failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this planning and contracting time.

Assumed Configuration of Well:

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[199]** 120	**[235]** 132	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull protector cap with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable

5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**<u>Add:</u>** **<u>Step (1)</u>** Subsea BOP and riser. **<u>Remove:</u>** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[14]** 14	**[18]** 18	**<u>Add:</u>** **<u>Step (2)</u>** Worksting with wireline lubricator. **<u>Remove:</u>** Tubing hanger plug.
7. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.) Install high pressure wear bushing.	**[464]** 48	**[491]** 48	**<u>Add:</u>** **<u>Step (3)</u>** Kill weight fluid and high pressure wear bushing. **<u>Remove:</u>** Primary barrier-completion string and workstring with wireline lubricator.
8. Run bit and scraper. Circulate out fill. POOH. Rig up and run gauge ring, cement bond log, gamma ray, casing-collar locator, etc. Set sump packer on workstring. Rig up separators, burner and associated equipment to flow and clean well.	72	72	
9. Pick up TCP guns and retrievable packer and RIH. Pressure up annulus or drop bar to fire guns to perforate the well. Check for fill. Pull out of hole. Trip in hole to clean out fill.	72	80	
10. If required, circulate in gel pill to control lost circulation; POOH.	12	12	
11. Pick up gravel pack tools including packer and RIH. (Screens, DH gauges, washpipe, etc.)	20	20	

12. Perform mini-frac and analysis. Pump gravel into place and reverse out excess gravel. Pull out with reverse flapper closed to prevent lost circulation. POOH.	120	120	
13. Run workstring with high pressure wear bushing retrieving tool to retrieve wear bushing from horizontal subsea tree. Test BOP's.	24	28	
14. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Install isolation sleeve with wireline. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
15. Rig up and pull isolation sleeve from tubing hanger; rig down wireline. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	**Add:** **Step (4)** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **Remove:** Kill fluid and high pressure wear bushing.
16. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**Add:** **Step (5)** Tubing hanger plug, SCSSV. **Remove:** Subsea test tree, completion riser, surface flowhead.
17. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	

18. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (6)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.
19. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.
Total Hours for This Procedure	**927**	**1047**	

16.

Horizontal Subsea Tree Operations
Repair Completion System Leak

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Repair Completion System Leak is an "unplanned" operation caused by a completion system failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this planning and contracting time.

<u>Assumed Configuration of Well:</u>

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	**Oprn. Time hours**		**Component add / remove (for RISKEX calculations)**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[199]** 120	**[235]** 132	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull trash cover with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable

5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**Add:** **Step (1)** Subsea BOP and riser. **Remove:** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[22]** 14	**[26]** 18	**Add:** **Step (2)** Workstring with wireline lubricator. **Remove:** Tubing hanger plug.
7. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	
8. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	**[144]** 48	**[159]** 48	**Add:** **Step (3)** Kill weight fluid. **Remove:** Primary barrier-completion string, workstring and wireline lubricator.
9. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	96	111	
10. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	**Add:** **Step (4)** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **Remove:** Kill fluid.

11. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**<u>Add:</u>** **<u>Step (5)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** **Tubing riser,** test tree, surface flowhead.
12. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
13. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (6)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.
14. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline jumper.
Total Hours for This Procedure	**615**	**723**	

17.

Horizontal Subsea Tree Operations
Repair / Replace Subsea Tree

<u>Resource Requirement</u>

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

<u>Assumed Vessel Availability</u>

- Repair / Replace Subsea Tree is an "unplanned" operation caused by a completion system failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this planning and contracting time.

<u>Assumed Configuration of Well:</u>

- In the production mode a wellhead connector attaches the wellhead housing to the subsea horizontal tree. The BOP and riser attach to the subsea horizontal tree with another wellhead connector.
- The subsea horizontal tree module includes production and annulus valves, attachment mechanisms to connect the production flowline, hydraulic and electrical connections and a control pod.

Procedure Step	**Oprn. Time hours**		**Component add / remove**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[199]** 120	**[235]** 132	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull trash cover with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable

5. Make up high pressure well cap retrieving tool and run on drillpipe workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**<u>Add:</u>** **<u>Step (1)</u>** Subsea BOP and riser. **<u>Remove:</u>** High pressure well cap.
6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline unit and pull tubing hanger plug. Kill well by bullheading in kill weight fluid. Work tubing from packer to circulate kill-weight fluid. If tubing fails to pull from packer, pull dummy from side pocket mandrel located near packer or run tubing punch and perforate tubing immediately above packer.	**[22]** 14	**[26]** 18	**<u>Add:</u>** **<u>Step (2)</u>** Workstring with wireline lubricator. **<u>Remove:</u>** Tubing hanger plug.
7. Circulate kill weight fluid down tubing and displace annulus fluid.	8	8	
8. Pull completion riser and tubing and retrieve completion equipment. (This may require extensive fishing to retrieve the tubing and completion equipment if the tubing fails to release from packer seal assembly.)	**[48]** 48	**[48]** 48	**<u>Add:</u>** **<u>Step (3)</u>** Kill weight fluid. **<u>Remove:</u>** Primary barrier-completion string, workstring and wireline lubricator.
9. Run bridge plug on work string. Set plug(s) to secure well. Pull BOP and riser.	**[345]** 52	**[421]** 72	**<u>Add:</u>** **<u>Step (4)</u>** Bridge plug. **<u>Remove:</u>** Subsea BOP's and riser.
10. Rig up and launch ROV to disconnect flowline and controls jumpers. Run disconnect tool and disconnect flowline jumpers. Run tools to release controls jumpers. Disconnect controls jumpers. Retrieve tools and ROV and rig down.	60	72	
11. Run tree retrieving tool on workstring and connect to tree. Release tree and retrieve to surface. Move tree to work or storage area.	42	48	

12. Move replacement tree to moonpool. Run replacement tree on running string. Land and latch tree. Test and function tree. Unlatch tree running tool and retrieve to surface.	52	60	
13. Rig up and launch ROV to re-connect flowline and controls jumpers. Run connection tool and connect flowline jumper. Run tools to re-connect controls jumpers. Re-connect controls jumper. Retrieve tools and ROV and rig down.	48	54	
14. Move BOP's to moonpool and rig up to run marine riser.	12	12	
15. Run Marine Riser and BOP.	45	65	
16. Test BOP's and retrieve bridge plug(s).	34	38	
17. Rig up and run completion string according to completion procedures (torque-turn, internal testing, tubing make up, etc.) Space out and install subsea tubing hanger and tubing hanger running-tool with subsea test tree on completion riser. Continue to run completion string with completion riser. Stab into packer. Close BOP's and test packer. Rig up surface flow head, surface slick joint and all surface equipment. Land and lock tubing hanger. Test function through umbilical. Close SCSSV.	**[96]** 96	**[111]** 111	**Add:** **Step (5)** Subsea BOP's and riser. **Remove:** Bridge plug.
18. Open flow initiation valve. Displace landing string with nitrogen and take returns through tree, BOP and choke line. Unload well to rig to flow, clean and test well. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	**[96]** 96	**[105]** 105	**Add:** **Step (5)** Subsea tubing hanger, tubing string, packer, test tree, tubing riser, surface flowhead. **Remove:** Kill fluid.

19. Rig up wireline; set tubing hanger plug; rig down wireline. Unlatch tubing hanger retrieving tool and pull out of hole with completion riser and subsea test tree. Rig down subsea test tree. 4/6+26/38+2 = 32/46	**[52]** 32	**[72]** 46	**<u>Add:</u>** **<u>Step (7)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** **Tubing riser,** test tree, surface flowhead.
20. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
21. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (8)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.
22. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**<u>Add:</u>** Flowline flying leads.
Total Hours for This Procedure	**960**	**1144**	

18.

Horizontal Subsea Tree Operations
Coiled Tubing Downhole Repair

Resource Requirement

- The resource vessel for this operation is an 8-point MODU with conventional anchors.

Assumed Vessel Availability

- Coiled Tubing Downhole Repair is an "unplanned" operation caused by a completion system failure prior to zone depletion. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this planning and contracting time.

Procedure Step	**Oprn. Time hours**		**Component add / remove**
Water Depth, feet =	4000	6000	
1. Mobilization and Positioning/Mooring Time	**[199]** 120	**[235]** 132	**Step [0]** Not Applicable
2. Move BOP's to moonpool and rig up to run marine riser. Pull trash cover with downline.	12	12	Not Applicable
3. Run Marine Riser and BOP.	45	65	Not Applicable
4. Test BOP's.	22	26	Not Applicable
5. Make up high pressure well cap retrieving tool and run on drillpipe or tubing workstring to retrieve high pressure well cap.	**[10]** 10	**[12]** 12	**Add:** **Step (1)** Subsea BOP and riser. **Remove:** High pressure well cap.

6. Re-run workstring with tubing hanger retrieving tool; latch tubing hanger and test. Rig up wireline or coiled tubing unit and pull tubing hanger plug and install isolation sleeve in tubing hanger. Kill (or partially kill) well by bull heading in kill weight fluid. Perform remedial operation. An arbitrary time of 48 hours is allowed for performing the coiled tubing operation such as: plugging a depleted zone and opening and testing a new zone or acidizing a zone or installing an insert valve in a failed SCSSV.	**[146]** 70	**[179]** 74	**<u>Add:</u>** **<u>Step (2)</u>** Tubing hanger isolation sleeve; workstring completion riser with surface lubricator, flowhead and coiled tubing. **<u>Remove:</u>** Tubing hanger plug; SCSSV.
7. Pull isolation sleeve from tubing hanger with coiled tubing unit. Displace landing string with nitrogen. Unload well to rig to establish flow. Close subsea valves and SCSSV to secure well. Circulate kill fluid into landing string.	96	105	
8. Set tubing hanger plug; rig down coiled tubing unit. Unlatch tubing hanger retrieving tool and workstring and tubing hanger retrieving tool.	**[32]** 12	**[44]** 18	**<u>Add:</u>** **<u>Step (3)</u>** Tubing hanger plug, SCSSV. **<u>Remove:</u>** Tubing hanger isolation sleeve; workstring completion riser with surface lubricator, flowhead and coiled tubing.
9. Make up tree cap and run in hole on running string. Set and test tree cap with mechanical tubing hanger running tool. Displace riser and stack while pulling out of hole with running string.	20	26	
10. Pull BOP and marine riser. (Set cover with downline.)	**[92]** 38	**[114]** 54	**<u>Add:</u>** **<u>Step (4)</u>** High pressure tree cap. **<u>Remove:</u>** Subsea BOP's and riser.

11. Run well Jumper. Start-up and commissioning. (Rig ROV installs Flying Leads off the critical path.)	54	60	**Add:** Flowline jumper.
Total Hours for This Procedure	**499**	**584**	

19.

Subsea System Operations
Repair / Flowline and/or Pipeline End Manifold (PLEM)

Risk of a blowout is negligible during these subsea equipment operations.

Resource Requirement

- The resource vessels for this operation are a Diving Service Vessel (DSV) for initial surveys to determine problem and a Heavy Lift Vessel to perform the repair.

Assumed Vessel Availability

- Repair / Flowline and/or Pipeline End Manifold (PLEM) is an "unplanned" operation caused by a subsea system failure. Availability time is a user-input parameter that includes time to plan and to contract a rig and services. Production is shut-in but repair costs are negligible during this time.

Procedure Step	Non Resource (Planning) hours		Heavy Lift Vessel hours		Umbilical Install'n Vessel hours		Multi-Service Vessel hours		Diving Service Vessel hours	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	[4]*	*	NA	NA	NA	NA	*	*
2. Decommission flowlines immediately to minimize environmental damage. Inspection to determine problem. (Diving Service Vessel for 14 / 14 days)	NA	NA	NA	NA	NA	NA	NA	NA	336	336
3. Plan work: 2 months. Build 2-PLEMs, 2-jumpers, Contract vessel: 6 months	5760	5760	NA	NA	NA	NA	NA	NA	NA	NA
4. Install PLEMs and Jumpers to repair line. (Heavy Lift Vessel for 2 weeks)	NA	NA	336	336	NA	NA	NA	NA	NA	NA
5. Recommission flowlines. (2 weeks)	336	336								
Total Hours for This Procedure	6096	6096	336	336					336	336

[4] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

20.

Subsea System Operations
Repair / Replace Flowline Jumpers

Risk of a blowout is negligible during these subsea equipment operations.

Resource Requirement

- The resource vessels for this operation are a Diving Service Vessel (DSV) for initial surveys to determine problem and a Multi-Service Vessel to perform the repair.

Assumed Vessel Availability

- Repair or replace Flowline Jumper is an "unplanned" operation caused by a subsea system failure. Availability time(s) is a user-input parameter that includes time to plan and to contract a vessel and services. Production is shut-in but repair costs are negligible during this time.

Procedure Step	Non Resource (Planning) hours		Heavy Lift Vessel hours		Umbilical Install'n Vessel hours		Multi-Service Vessel hours		Diving Service Vessel hours	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	[5]*	*	NA	NA	*	*	*	*
2. Decommission flowlines immediately to minimize environmental damage. Inspection to determine problem. (Diving Service Vessel for 14 / 14 days)	NA	NA	NA	NA	NA	NA	NA	NA	336	336
3. Plan work and contract vessel: 4 weeks. Build new jumper: 6 weeks.	1680	1680	NA	NA	NA	NA	NA	NA	NA	NA
4. Recover damaged jumper; install replacement jumper: 2+ weeks)	NA	NA	NA	NA	NA	NA	350	450	NA	NA
5. Recommission flowlines. (2 weeks)	336	336								
Total Hours for This Procedure	2016	2016					350	450	336	336

[5] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

21.

Subsea System Operations
Repair / Replace Hydraulic Umbilical

Risk of a blowout is negligible during these subsea equipment operations.

<u>Resource Requirement</u>

- The resource vessels for this operation are a Diving Service Vessel (DSV) for initial surveys to determine problem and a Multi-Service Vessel to perform the repair.

<u>Assumed Vessel Availability</u>

- Repair or replace Hydraulic Umbilical including UTS is an "unplanned" operation caused by a subsea system failure. Availability time is a user-input parameter that includes time to plan and to contract a vessel. Production is shut-in but repair costs are negligible during this time.

Procedure Step	**Non Resource (Planning) hours**		**Heavy Lift Vessel hours**		**Umbilical Install'n Vessel hours**		**Multi-Service Vessel hours**		**Diving Service Vessel hours**	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	NA	NA	NA	NA	[6]*	*	*	*
2. Inspection to determine problem. (Diving Service Vessel for 14 / 14 days)	NA	NA	NA	NA	NA	NA	NA	NA	336	336
3. Plan work and contract vessel: 4 weeks. Build new splice section: 12 weeks.	2688	2688	NA	NA	NA	NA	NA	NA	NA	NA
4. Recover damaged umbilical; install replacement umbilical and test: 2+ weeks)	NA	NA	NA	NA	NA	NA	350	450	NA	NA
5. Recommission umbilical system (line flushing and testing). (2 weeks)	336	336								
Total Hours for This Procedure	3024	3024					350	450	336	336

[6] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

22.

Subsea System Operations
Repair / Replace Electrical Umbilical

Risk of a blowout is negligible during these subsea equipment operations.

<u>Resource Requirement</u>

- The resource vessels for this operation are a Diving Service Vessel (DSV) for initial surveys to determine problem and a Multi-Service Vessel to perform the repair.

<u>Assumed Vessel Availability</u>

- Repair or replace Electrical Umbilical including EDU is an "unplanned" operation caused by a subsea system failure. Availability time is a user-input parameter that includes time to plan and to contract a vessel. Production is shut-in but repair costs are negligible during this time.

Procedure Step	Non Resource (Planning) hours		Heavy Lift Vessel hours		Umbilical Install'n Vessel hours		Multi-Service Vessel hours		Diving Service Vessel hours	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	NA	NA	NA	NA	[7]*	*	*	*
2. Inspection to determine problem. (Diving Service Vessel for 14 / 14 days)	NA	NA	NA	NA	NA	NA	NA	NA	336	336
3. Plan work and contract vessel: 4 weeks. Build new splice section: 12 weeks.	2688	2688	NA	NA	NA	NA	NA	NA	NA	NA
4. Recover damaged umbilical; install replacement umbilical and test: 2+ weeks)	NA	NA	NA	NA	NA	NA	350	450	NA	NA
5. Recommission electrical umbilical system. (2 weeks)	336	336								
Total Hours for This Procedure	3024	3024					350	450	336	336

[7] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

23.

Subsea System Operations
Repair / Replace Well Control Pod / Subsea Choke

Risk of a blowout is negligible during these subsea equipment operations.

<u>Resource Requirement</u>

- The resource vessel for this operation is a Diving Service Vessel with a lift line. Assumes that a replacement pod / choke is available.

<u>Assumed Vessel Availability</u>

- Repair or replace Well Control Pod / Subsea Choke is an "unplanned" operation caused by a subsea system failure. Availability time is a user-input parameter that includes time to plan and to contract a vessel. Production is shut-in but repair costs are negligible during this time.

Procedure Step	**Non Resource (Planning) hours**		**Heavy Lift Vessel hours**		**Umbilical Install'n Vessel hours**		**Multi-Service Vessel hours**		**Diving Service Vessel hours**	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	NA	NA	NA	NA	NA	NA	[8]*	*
2. Shut-in production; conduct diagnostic simulation from host.	48	48	NA	NA	NA	NA	NA	NA	NA	NA
3. Spot hire DSV; mob and rig up for equipment / ROV tooling: 1 week. Recover damaged pod / choke; install replacement pod / choke: 4/6 days.	NA	NA	NA	NA	NA	NA	NA	NA	264	312
4. Test and initiate startup. 1 day	24	24								
Total Hours for This Procedure	72	72							264	312

[8] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

24.

Subsea System Operations
Repair / Replace Well Flying Lead

Risk of a blowout is negligible during these subsea equipment operations.

<u>Resource Requirement</u>

- The resource vessel for this operation is a Multi-Service Vessel.

<u>Assumed Vessel Availability</u>

- Repair or replace Well Flying Lead is an "unplanned" operation caused by a subsea system failure. Availability time is a user-input parameter that includes time to plan and to contract a vessel and services. Production is shut-in but repair costs are negligible during this time.

Procedure Step	Non Resource (Planning) hours		Heavy Lift Vessel hours		Umbilical Install'n Vessel hours		Multi-Service Vessel hours		Diving Service Vessel hours	
Water Depth, feet =			4000	6000	4000	6000	4000	6000	4000	6000
1. Availability. (User input for planning, and contracting Vessel for repair operation.)	NA	NA	NA	NA	NA	NA	[9]*	*	*	*
2. Inspection to determine problem. (Diving Service Vessel for 14 / 14 days)	NA	NA	NA	NA	NA	NA	NA	NA	336	336
3. Plan work and contract vessel: 4 weeks. Build new flying lead: 6 weeks.	1680	1680	NA	NA	NA	NA	NA	NA	NA	NA
4. Recover damaged flying lead; install replacement flying lead: 5/6 days)	NA	NA	NA	NA	NA	NA	120	144	NA	NA
Total Hours for This Procedure	1680	1680					96	144	336	336

[9] Basic user input for vessel availability is based on location, number of vessels servicing the area, etc.

The algorithm developed to calculate total production downtime for various subsea operation is illustrated below (the '#' mark refers to step in procedure):

Procedure 19: Pipeline or PLEM Repair Time

DSV (#1 avail. time + #2 work time) + Greater Value of [#3 (plan work + build equipment + contract vessel) OR #1 Heavy Lift Vessel (avail. time)] + #4 Heavy Lift Vessel work time + #5 Recommission flowlines.

Procedure 20: Repair/Replace Flowline Jumpers

DSV (#1 avail. time + #2 work time) + Greater Value of [#3 (plan work + contract vessel) OR #1 Multi-Service Vessel (avail. time)] + #4 Multi-Service Vessel work time + #5 Recommission flowlines.

Procedure 21: Repair/Replace Hydraulic Umbilical

DSV (#1 avail. time + #2 work time) + Greater Value of [#3 (plan work + build new splice section + contract vessel) OR #1 Multi-Service Vessel (avail. time)] + #4 Multi-Service Vessel work time + #5 Recommission, umbilical system.

Procedure 22: Repair/Replace Electrical Umbilical

DSV (#1 avail. time + #2 work time) + Greater Value of [#3 (plan work + build new splice section + contract vessel) OR #1 Multi-Service Vessel (avail. time)] + #4 Multi-Service Vessel work time + #5 Recommission umbilical system.

Procedure 23: Repair/Replace Well Control Pod / Subsea Choke

#2 Diagnostic simulation from host + DSV (#1 avail. time + #3 work time) + #4 Test and startup.

Procedure 24: Repair/Replace Well Flying Lead

DSV (#1 avail. time + #2 work time) + Greater Value of [#3 (plan work + build new flying lead + contract vessel) OR #1 Multi-Service Vessel (avail. time)] + #4 Multi-Service Vessel work time.

Subsea Component to Repair / Replace	Number of Well Effected	Procedure Number
Primary Subsea System (8 wells maximum)		
Pipeline (2 total)	half	19
PLEM (2 total)	half	19
Flowline Jumper (2 total – from PLEM to manifold)	half	20
Well Jumper (each well – from manifold to well)	one	20
System Hydraulic Umbilical	all	21
System Electrical Umbilical	all	22
Well Control Pod	one	23
Well Subsea Choke	one	23
Well Flying Lead (hydraulic and/or electrical)	one	24
Subsea Extension System (9 or more subsea wells)		
Extension Pipeline (2 total)	½ of # > 8	19
Extension PLEM (4 total)	½ of # > 8	19
Well Jumper (each well – from manifold to well)	one	20

Subsea Component to Repair / Replace	**Number of Well Effected**	**Procedure Number**
Extension Hydraulic Umbilical	all > 8	21
Extension Electrical Umbilical	all > 8	22
Well Control Pod	one	23
Well Subsea Choke	one	23
Well Flying Lead (hydraulic and/or electrical)	one	24

6 CAPITAL EXPENDITURES, CAPEX

This section documents how the capital expenditure, CAPEX, has been estimated. CAPEX includes two parts:

- The well system materials
- Vessel costs for the well system installations.

Well system material lists are shown in the tables in this section. Rig and vessel resources and installation times from which the installation costs are derived are summarized in the Operational Procedures Section, Section 5, of this report.

For comparison purposes the dry tree tieback alternatives CAPEX are included.

6.1 Dry Tree Well System Alternatives Materials

Riser related materials CAPEX for the dry tree riser alternatives was developed by the Phase I of the Dry Tree Tieback Alternatives Study and have been included to permit comparison of Dry Tree Systems and Subsea Systems. The riser related capital expenditures are determined for the following alternatives:

- TLP or SPAR
- Dual casing risers, single casing risers and tubing riser
- 6 well system or 12 well system
- 4000 foot water depth ore 6000 foot water depth

For user defined TLP or SPAR platform and dual, single or tubing riser alternative the methodology determines the CAPEX for a particular water depth and well count by linear interpolation between the 6 and 12 well systems and 4000 and 6000 foot water depths.

The SPAR CAPEX includes air can buoyancy to support the production risers. The TLP CAPEX includes riser tensioners. A TLP load penalty of $5 per pound of riser tension is included to cover the additional costs for a larger TLP to support greater riser loads. This TLP load penalty amounts to one of the greatest components of the TLP riser systems and is particularly significant for the dual casing riser system.

These CAPEX materials costs do not include the following:

- TLP or Spar platform expenditures
- Processing or drilling facilities on the platform
- Export Offtake systems such as pipelines and risers
- Initial drilling of wells (all wells are assumed to be predrilled)
- Downhole completion equipment (downhole completion components are assumed to be the same in all wells and therefore unnecessary for comparison of the alternative systems)

6.2 Subsea Well System Alternatives Materials

CAPEX for the subsea well system materials includes:

- Flowlines between the subsea wells and host facility,
- Pipeline end manifolds, PLEM,
- Subsea production manifolds,
- Jumpers to connect the pipeline and manifold,
- Hydraulic and electrical umbilicals,
- Well jumpers, and
- Conventional subsea trees or horizontal subsea trees.

Simple algorithms based on size and length estimate flowline and umbilical materials and installation costs. Typical costs are provided for manifolds, termination units, jumper and trees. These component costs are summarized in algorithms to estimate the subsea system materials CAPEX based on flowline size, length, water depth and number and type of subsea wells.

6.3 Initial Well System Installation

Installation costs are calculated by multiplying the user-defined rig/vessel/equipment spread costs by the appropriate operating times that are estimated for the installation procedures. Spread costs are basic input data that may be supplied by the user. The base case values are shown in Table 6.1. Default values for the spread costs are supplied in the spreadsheet program.

Table 6.1: Spread Cost for Installation and Repair Vessels – Base Case for This Study

Repair Resource	Availability Time, days	Spread Cost $/day
Rig (MODU) (8 point spread moored)	120	$240,000
Pipeline Installation Vessel (DP, heavy lift capability, etc.)	60	$340,000
Umbilical Installation Vessel	30	$200,000
MSV Spread (With capability to support lightweight packages.)	7	$60,000
DSV Spread (ROV only – monitor and visual checks)	5	$30,000
TLP or SPAR Platform Rig	30	$120,000
Wireline or Coiled Tubing Unit	2	$25,000

The following resources, rigs/vessels/equipment, are used for various operations.

- Rig (MODU) (8 point spread moored)
- Pipeline Installation Vessel (DP, heavy lift capability, etc.)
- Umbilical Installation Vessel
- MSV Spread (Capable of supporting lightweight packages.)
- DSV Spread (ROV only – monitor and visual checks)
- TLP or SPAR Platform Rig
- Wireline or Coiled Tubing Unit

Installation times are summarized in the Operating Procedures Section, Section 5, where the resource times are derived for each installation operation. These operations include:

- Installation of frac-pack completion
- Installation of horizontal gravel packed liner completions
- Installation of pipelines (2)
- Installation of hydraulic umbilical and UTA
- Installation of electrical umbilical and EDU
- Installation of production manifold and P/L jumpers
- Installation of subsea wells including the subsea trees with flying leads to the UTA and EDU.

The following tables show the well systems materials costs calculation worksheets.

Table 6.2: Materials Cost* ($MM) for Dry Tree Tieback Systems - TLP

TLP	**6 Wells**		**12 Wells**	
	WD= 4000 feet	**WD= 6000 feet**	**WD= 4000 feet**	**WD= 6000 feet**
Tubing Riser	30	36	51	60
Single Casing Riser	34	44	66	86
Dual Casing Riser	59	80	116	157

* Note that a large part of this materials cost is the TLP weight penalty of $5 per pound tensioning load.

Table 6.3: Materials Cost ($MM) for Dry Tree Tieback Systems - SPAR

SPAR	6 Wells		12 Wells	
	WD= 4000 feet	WD= 6000 feet	WD= 4000 feet	WD= 6000 feet
Tubing Riser	33	38	54	61
Single Casing Riser	24	29	48	58
Dual Casing Riser	30	37	58	73

Table 6.4: Materials Cost and Subsea Equipment Installation Cost ($MM) for Subsea Tieback Systems

SUBSEA	6 Wells		12 Wells	
	WD= 4000 feet	WD= 6000 feet	WD= 4000 feet	WD= 6000 feet
Conventional Tree	215	216	271	271
Horizontal	210	211	262	262

The following tables show the detailed well systems materials costs calculation worksheets (for subsea tieback systems the subsea equipment installation cost is also included).

6.3.1 Dry Tree Well System CAPEX

Item No.	SPAR - 6 Well Scenario Dual Casing Riser CAPEX COSTS	4000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	6000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$29,525**				**$36,989**
1.1	**Surface Wellhead Equipment**				**$3,067**				**$3,067**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$323	$1,938	1	323	$323	$1,938
1.1.2	11" 10,000 psi Surface Wellhead	1	128	$128	$769	1	128	$128	$769
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$360	1	60	$60	$360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	Riser Equipment				$17,117				$23,138
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$250	$1,500	1	250	$250	$1,500
1.2.2	Instrumentation Joint, Equipment, Umbilical	1	96	$96	$578	1	96	$96	$578
1.2.3	63' Riser Joints 12 3/4" 73.15 ppf X-80	52	16	$848	$5,086	83	16	$1,353	$8,117
1.2.4	Keel Joint	1	403	$403	$2,419	1	403	$403	$2,419
1.2.5	Riser Pup Joints	1	81	$81	$484	1	81	$81	$484
1.2.6	Stem Jts.	1	185	$185	$1,110	1	185	$185	$1,110
1.2.7	Tapered Stress Joint	1	226	$226	$1,358	1	226	$226	$1,358
1.2.8	Flanged,Transition, Spacer Jts./Well	1	503	$503	$3,019	1	476	$476	$2,855
1.2.9	9 3/4"C-95 59.2 ppf Inner Riser VAM ACE	4000	0	$148	$891	6000	0	$223	$1,336
1.2.10	9 3/4" Tieback Adapter	1	50	$50	$297	1	50	$50	$297
1.2.11	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$63	$375	6000	0	$94	$563
1.2.12	Syntactic Foam Buoyancy	0	0	$0	$0	1	420	$420	$2,520
1.3	Riser Tensioners				$8,081				$9,235
1.3.1	Air Can Riser Tensioners Note for 6000' additional syntactic foam is used	7	192	$1,347	$8,081	8	192	$1,539	$9,235
1.4	**Riser Installation Equipment**				**$612**				**$612**
1.4.1	Riser & Wellhead Running Tools	0.166666	577	$96	$577	0.166666	577	$96	$577
	Bolt Tensionesrs	0.166666	35	$6	$35	0.166666	35	$6	$35
1.5	**Umbilicals**				**$648**				**$936**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$648	6500	0	$156	$936
1.6	**Intervention**				**$0**				**$0**
1.6.1	ROV intervention system & tooling	1	0	$0	$0	1	0	$0	$0
1.7	**Vessel Cost Penalty (Riser Tension)**	**0.16666**	**0**	$0	**$0**	**0.16666**	**0**	$0	**$0**
2	**Project Management**				**$0**				**$0**
2.1	AOI Project Management	0.166666	0	$0	$0	0.166666	0	$0	$0
2.2	Vendor Project Management	0.166666	0	$0	$0	0.166666	0	$0	$0
2.4	Auditing Manufacturing Sites	0.166666	0	$0	$0	0.166666	0	$0	$0
3	**Engineering**				**$0**				**$0**
3.1	System analysis	0.166666	0	$0	$0	0.166666	0	$0	$0
3.2	Connector testing	0.166666	0	$0	$0	0.166666	0	$0	$0
3.3	Soil boring and analysis	0.166666	0	$0	$0	0.166666	0	$0	$0
3.4	Detail engineering including tooling	0.166666	0	$0	$0	0.166666	0	$0	$0
4	**TOTAL CAPEX COSTS ($1000)**			**$4,921**	**$29,525**			**$6,165**	**$36,989**

Item No.	SPAR - 12 Well Scenario Dual Casing Riser CAPEX COSTS	4000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	6000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$58,438**				**$73,365**
1.1	**Surface Wellhead Equipment**				**$6,134**				**$6,134**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$323	$3,876	1	323	$323	$3,876
1.1.2	11" 10,000 psi Surface Wellhead	1	128	$128	$1,538	1	128	$128	$1,538
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$720	1	60	$60	$720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	**Riser Equipment**				**$34,234**				**$46,276**
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$250	$3,000	1	250	$250	$3,000
1.2.2	Instrumentation Joint, Equipment, Umbilical	1	96	$96	$1,156	1	96	$96	$1,156
1.2.3	63' Riser Joints 12 3/4" 73.15 ppf X-80	52	16	$848	$10,171	83	16	$1,353	$16,235
1.2.4	Keel Joint	1	403	$403	$4,838	1	403	$403	$4,838
1.2.5	Riser Pup Joints	1	81	$81	$968	1	81	$81	$968
1.2.6	Stem Jts.	1	185	$185	$2,220	1	185	$185	$2,220
1.2.7	Tapered Stress Joint	1	226	$226	$2,716	1	226	$226	$2,716
1.2.8	Flanged,Transition, Spacer Jts./Well	1	503	$503	$6,038	1	476	$476	$5,711
1.2.9	9 3/4"C-95 59.2 ppf Inner Riser VAM ACE	4000	0	$148	$1,782	6000	0	$223	$2,673
1.2.10	9 3/4" Tieback Adapter	1	50	$50	$594	1	50	$50	$594
1.2.11	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$63	$750	6000	0	$94	$1,125
1.2.12	Syntactic Foam Buoyancy	0	0	$0	$0	1	420	$420	$5,040
1.3	**Riser Tensioners**				**$16,162**				**$18,470**
1.3.1	Air Can Riser Tensioners Note for 6000' additional syntactic foam is used	7	192	$1,347	$16,162	8	192	$1,539	$18,470
1.4	**Riser Installation Equipment**				**$612**				**$612**
1.4.1	Riser & Wellhead Running Tools	0.083333	577	$48	$577	0.083333	577	$48	$577
	Bolt Tensionesrs	0.083333	35	$3	$35	0.083333	35	$3	$35
1.5	**Umbilicals**				**$1,296**				**$1,872**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$1,296	6500	0	$156	$1,872
1.6	**Intervention**				**$0**				**$0**
1.6.1	ROV intervention system & tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
1.7	**Vessel Cost Penalty (Riser Tension)**	**0.083333**	**0**	$0	**$0**	**0.083333**	**0**	$0	**$0**
2	**Project Management**				**$0**				**$0**
2.1	AOI Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
2.2	Vendor Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
2.4	Auditing Manufacturing Sites	0.083333	0	$0	$0	0.083333	0	$0	$0
3	**Engineering**				**$0**				**$0**
3.1	System analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
3.2	Connector testing	0.083333	0	$0	$0	0.083333	0	$0	$0
3.3	Soil boring and analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
3.4	Detail engineering including tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
4	**TOTAL CAPEX COSTS**			**$4,870**	**$58,438**			**$6,114**	**$73,365**

Item No.	TLP - 6 Well Scenario Dual Casing Riser CAPEX COSTS	4000' Water Depth				6000' Water Depth			
		Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$ 58,504**				**$ 79,515**
1.1	**Surface Wellhead Equipment**				**$ 3,067**				**$ 3,067**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$ 323	$ 1,938	1	323	$ 323	$ 1,938
1.1.2	11" 10,000 psi Surface Wellhead	1	128	$ 128	$ 769	1	128	$ 128	$ 769
1.1.3	Tree/Wellhead Work Platforms	1	60	$ 60	$ 360	1	60	$ 60	$ 360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$ -	$ -	1	0	$ -	$ -
1.2	**Riser Equipment**				**$ 14,080**				**$ 17,843**
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$ 250	$ 1,500	1	250	$ 250	$ 1,500
1.2.2	Instrumentation Joints and Equipment	1	285	$ 285	$ 1,708	1	285	$ 285	$ 1,708
1.2.3	63' Riser Joints - 12-3/4" 73.15 ppf X - 80	62	16	$ 1,011	$ 6,064	94	16	$ 1,532	$ 9,193
1.2.4	Riser Pup Joints - 12-3/4" Riser System	1	81	$ 81	$ 484	1	81	$ 81	$ 484
1.2.5	Rnge 3 Riser Joints - 9-3/4" 59.2 C - 95 Vam Ace	4000	0	$ 148	$ 891	6000	0	$ 223	$ 1,336
1.2.6	9 3/4" Tieback Adapter	1	50	$ 50	$ 297	1	50	$ 50	$ 297
1.2.7	Riser Pup Joints - 9-3/4" Riser System	1	4	$ 4	$ 22	1	4	$ 4	$ 22
1.2.8	Tensioner Joint	1	151	$ 151	$ 907	1	151	$ 151	$ 907
1.2.9	Tapered Stress Joint	1	226	$ 226	$ 1,358	1	226	$ 226	$ 1,358
1.2.10	Hvy. Wall, Transition, Spacer, Adj.Sub/Well	1	79	$ 79	$ 474	1	79	$ 79	$ 474
1.2.11	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$ 63	$ 375	6000	0	$ 94	$ 563
1.3	**Riser Tensioners**				**$ 8,700**				**$ 10,800**
1.3.1	Hydropneumatic Riser Tensioners	1	1450	$ 1,450	$ 8,700	1	1800	$ 1,800	$ 10,800
1.4	**Riser Installation Equipment**				**$ 259**				**$ 259**
1.4.1	Riser & Wellhead Running Tools	0.166667	259	$ 43	$ 259	0.166667	259	$ 43	$ 259
1.5	**Umbilicals**				**$648**				**$936**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$648	6500	0	$156	$936
1.6	**Intervention**				**$0**				**$0**
1.6.1	ROV intervention system & tooling	0.166667	0	$0	$0	0.166667	0	$0	$0
1.7	**Vessel Penalty Cost (Riser Tension)**	**0.166667**	**31750**	$ 5,292	**$ 31,750**	**0.166667**	**46610**	$ 7,768	**$ 46,610**
2	**Project Management**				**$0**				**$0**
2.1	AOI Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
2.2	Vendor Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
2.4	Auditing Manufacturing Sites	0.166667	0	$0	$0	0.166667	0	$0	$0
3	**Engineering**				**$0**				**$0**
3.1	System analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
3.2	Connector testing	0.166667	0	$0	$0	0.166667	0	$0	$0
3.3	Soil boring and analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
3.4	Detail engineering including tooling	0.166667	0	$0	$0	0.166667	0	$0	$0
4	**TOTAL CAPEX COSTS**			$ 58,504	**$ 58,504**			$ 79,515	**$ 79,515**

Item No.	TLP -12 Well Scenario Dual Casing Riser CAPEX COSTS	4000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	6000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$ 115,680**				**$ 157,361**
1.1	**Surface Wellhead Equipment**				**$ 6,134**				**$ 6,134**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$ 323	$ 3,876	1	323	$ 323	$ 3,876
1.1.2	11" 10,000 psi Surface Wellhead	1	128	$ 128	$ 1,538	1	128	$ 128	$ 1,538
1.1.3	Tree/Wellhead Work Platforms	1	60	$ 60	$ 720	1	60	$ 60	$ 720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$ -	$ -	1	0	$ -	$ -
1.2	**Riser Equipment**				**$ 28,161**				**$ 35,686**
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$ 250	$ 3,000	1	250	$ 250	$ 3,000
1.2.2	Instrumentation Joints and Equipment	1	285	$ 285	$ 3,416	1	285	$ 285	$ 3,416
1.2.3	63' Riser Joints - 12-3/4" 73.15 ppf X - 80	62	16	$ 1,011	$ 12,127	94	16	$ 1,532	$ 18,386
1.2.4	Riser Pup Joints - 12-3/4" Riser System	1	81	$ 81	$ 968	1	81	$ 81	$ 968
1.2.5	Rnge 3 Riser Joints - 9-3/4" 59.2 C - 95 Vam Ace	4000	0	$ 148	$ 1,782	6000	0	$ 223	$ 2,673
1.2.6	9 3/4" Tieback Adapter	1	50	$ 50	$ 594	1	50	$ 50	$ 594
1.2.7	Riser Pup Joints - 9-3/4" Riser System	1	4	$ 4	$ 45	1	4	$ 4	$ 45
1.2.8	Tensioner Joint	1	151	$ 151	$ 1,814	1	151	$ 151	$ 1,814
1.2.9	Tapered Stress Joint	1	226	$ 226	$ 2,716	1	226	$ 226	$ 2,716
1.2.10	Hvy. Wall, Transition, Spacer, Adj.Sub/Well	1	79	$ 79	$ 948	1	79	$ 79	$ 948
1.2.11	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$ 63	$ 750	6000	0	$ 94	$ 1,125
1.3	**Riser Tensioners**				**$ 17,400**				**$ 21,600**
1.3.1	Hydropneumatic Riser Tensioners	1	1450	$ 1,450	$ 17,400	1	1800	$ 1,800	$ 21,600
1.4	**Riser Installation Equipment**				**$ 259**				**$ 259**
1.4.1	Riser & Wellhead Running Tools	0.083333	259	$ 22	$ 259	0.083333	259	$ 22	$ 259
1.5	**Umbilicals**				**$ 1,296**				**$ 1,872**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$1,296	6500	0	$156	$1,872
1.6	**Intervention**				**$ -**				**$ -**
1.6.1	ROV intervention system & tooling	0.083333	0	$0	$ -	0.083333	0	$0	$ -
1.7	**Vessel Penalty Cost (Riser Tension)**	**0.083333**	**62430**	$ 5,203	**$ 62,430**	**0.083333**	**91810**	$ 7,651	**$ 91,810**
2	**Project Management**				**$ -**				**$ -**
2.1	AOI Project Management	0.083333	0	$0	$ -	0.083333	0	$0	$ -
2.2	Vendor Project Management	0.083333	0	$0	$ -	0.083333	0	$0	$ -
2.4	Auditing Manufacturing Sites	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3	**Engineering**				**$ -**				**$ -**
3.1	System analysis	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.2	Connector testing	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.3	Soil boring and analysis	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.4	Detail engineering including tooling	0.083333	0	$0	$ -	0.083333	0	$0	$ -
4	**TOTAL CAPEX COSTS**			$ 9,640	**$ 115,680**			$ 13,113	**$ 157,361**

Item No.	SPAR - 6 Well Scenario Single Casing Riser CAPEX	4000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost (1000$)	6000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost
1	**Manufacture/Materials**				**$ 24,167**				**$ 29,301**
1.1	**Surface Wellhead Equipment**				$ 2,907				$ 2,907
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$ 323	$ 1,938	1	323	$ 323	$ 1,938
1.1.2	11" 10,000 psi Surface Wellhead	1	102	$ 102	$ 609	1	102	$ 102	$ 609
1.1.3	Tree/Wellhead Work Platforms	1	60	$ 60	$ 360	1	60	$ 60	$ 360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	**1**	0	$ -	**$ -**	**1**	0	$ -	**$ -**
1.2	**Riser Equipment**				$ 15,400				$ 17,945
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$ 250	$ 1,500	1	250	$ 250	$ 1,500
1.2.2	Instrumentation Joint, Equipment, Umbilical	1	95	$ 95	$ 572	1	110	$ 110	$ 659
1.2.3	63' Riser Joints 9 3/4" 59.2 ppf C - 95	52	14	$ 723	$ 4,337	83	14	$ 1,154	$ 6,922
1.2.4	Keel Joint	1	401	$ 401	$ 2,408	1	401	$ 401	$ 2,408
1.2.5	Riser Pup Joints	1	73	$ 73	$ 440	1	73	$ 73	$ 440
1.2.6	Stem Jts.	1	181	$ 181	$ 1,084	1	181	$ 181	$ 1,084
1.2.7	Tapered Stress Joint	1	222	$ 222	$ 1,333	1	222	$ 222	$ 1,333
1.2.8	Flanged,Transition, Spacer Jts./Well	1	558	$ 558	$ 3,350	1	506	$ 506	$ 3,036
1.2.9	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$ 63	$ 375	6000	0	$ 94	$ 563
1.3	**Riser Tensioners**				**$ 4,601**				**$ 6,901**
1.3.1	Air Can Riser Tensioners	4	192	$ 767	$ 4,601	6	192	$ 1,150	$ 6,901
1.4	**Riser Installation Equipment**				**$ 612**				**$ 612**
1.4.1	Riser & Wellhead Running Tools	0.166666	577	$ 96	$ 577	0.166666	577	$ 96	$ 577
	Bolt Tensioners	0.166666	35	$ 6	$ 35	0.166666	35	$ 6	$ 35
1.5	**Umbilicals**				**$ 648**				**$ 936**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$ 648	6500	0	$156	$ 936
1.6	**Intervention**				**$ -**				**$ -**
1.6.1	ROV intervention system & tooling	1	0	$0	$ -	1	0	$0	$ -
1.7	**Vessel Cost Penalty (Riser Tension)**	**0.16666**	**0**	$ -	**$ -**	**0.16666**	**0**	$ -	**$ -**
2	**Project Management**				**$ -**				**$ -**
2.1	AOI Project Management	0.166666	0	$0	$ -	0.166666	0	$0	$ -
2.2	Vendor Project Management	0.166666	0	$0	$ -	0.166666	0	$0	$ -
2.4	Auditing Manufacturing Sites	0.166666	0	$0	$ -	0.166666	0	$0	$ -
3	**Engineering**				**$ -**				**$ -**
3.1	System analysis	0.166666	0	$0	$ -	0.166666	0	$0	$ -
3.2	Connector testing	0.166666	0	$0	$ -	0.166666	0	$0	$ -
3.3	Soil boring and analysis	0.166666	0	$0	$ -	0.166666	0	$0	$ -
3.4	Detail engineering including tooling	0.166666	0	$0	$ -	0.166666	0	$0	$ -
4	**TOTAL CAPEX COSTS ($1000)**			$ 4,028	**$ 24,167**			$ 4,884	**$ 29,301**

Item No.	SPAR - 12 Well Scenario Single Casing Riser CAPEX	4000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost	6000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost
1	**Manufacture/Materials**				**$ 47,723**				**$ 57,991**
1.1	**Surface Wellhead Equipment**				$ 5,814				$ 5,814
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$ 323	$ 3,876	1	323	$ 323	$ 3,876
1.1.2	11" 10,000 psi Surface Wellhead	1	102	$ 102	$ 1,218	1	102	$ 102	$ 1,218
1.1.3	Tree/Wellhead Work Platforms	1	60	$ 60	$ 720	1	60	$ 60	$ 720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	**1**	0	$ -	**$ -**	**1**	0	$ -	**$ -**
1.2	**Riser Equipment**				$ 30,799				$ 35,890
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$ 250	$ 3,000	1	250	$ 250	$ 3,000
1.2.2	Instrumentation Joint, Equipment, Umbilical	1	95	$ 95	$ 1,144	1	110	$ 110	$ 1,318
1.2.3	63' Riser Joints 9 3/4" 59.2 ppf C - 95	52	14	$ 723	$ 8,674	83	14	$ 1,154	$ 13,844
1.2.4	Keel Joint	1	401	$ 401	$ 4,816	1	401	$ 401	$ 4,816
1.2.5	Riser Pup Joints	1	73	$ 73	$ 880	1	73	$ 73	$ 880
1.2.6	Stem Jts.	1	181	$ 181	$ 2,168	1	181	$ 181	$ 2,168
1.2.7	Tapered Stress Joint	1	222	$ 222	$ 2,666	1	222	$ 222	$ 2,666
1.2.8	Flanged,Transition, Spacer Jts./Well	1	558	$ 558	$ 6,701	1	506	$ 506	$ 6,072
1.2.9	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$ 63	$ 750	6000	0	$ 94	$ 1,125
1.3	**Riser Tensioners**				**$ 9,202**				**$ 13,802**
1.3.1	Air Can Riser Tensioners	4	192	$ 767	$ 9,202	6	192	$ 1,150	$ 13,802
1.4	**Riser Installation Equipment**				**$ 612**				**$ 612**
1.4.1	Riser & Wellhead Running Tools	0.083333	577	$ 48	$ 577	0.083333	577	$ 48	$ 577
	Bolt Tensioners	0.083333	35	$ 3	$ 35	0.083333	35	$ 3	$ 35
1.5	**Umbilicals**				**$ 1,296**				**$ 1,872**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$ 1,296	6500	0	$156	$ 1,872
1.6	**Intervention**				**$ -**				**$ -**
1.6.1	ROV intervention system & tooling	0.083333	0	$0	$ -	0.083333	0	$0	$ -
1.7	**Vessel Cost Penalty (Riser Tension)**	**0.083333**	**0**	$ -	**$ -**	**0.083333**	**0**	$ -	**$ -**
2	**Project Management**				**$ -**				**$ -**
2.1	AOI Project Management	0.083333	0	$0	$ -	0.083333	0	$0	$ -
2.2	Vendor Project Management	0.083333	0	$0	$ -	0.083333	0	$0	$ -
2.4	Auditing Manufacturing Sites	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3	**Engineering**				**$ -**				**$ -**
3.1	System analysis	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.2	Connector testing	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.3	Soil boring and analysis	0.083333	0	$0	$ -	0.083333	0	$0	$ -
3.4	Detail engineering including tooling	0.083333	0	$0	$ -	0.083333	0	$0	$ -
4	**TOTAL CAPEX COSTS**			$ 3,977	**$ 47,723**			$ 4,833	**$ 57,991**

Item No.	TLP - 6 Well Scenario Single Casing Riser	4000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost	6000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost
1	**Manufacture/Materials**				**$33,568**				**$44,102**
1.1	**Surface Wellhead Equipment**				**$2,907**				**$2,907**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$323	$1,938	1	323	$323	$1,938
1.1.2	11" 10,000 psi Surface Wellhead	1	102	$102	$609	1	102	$102	$609
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$360	1	60	$60	$360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	**Riser Equipment**				**$10,366**				**$13,222**
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$250	$1,500	1	250	$250	$1,500
1.2.2	Instrumentation Joint and Equipment	1	65	$65	$393	1	65	$65	$393
1.2.3	63' Riser Joints 9 3/4" 59.2 ppf C - 95	62	14	$862	$5,171	94	14	$1,307	$7,840
1.2.4	Riser Pup Joints	1	73	$73	$440	1	73	$73	$440
1.2.5	Tensioner Joint	1	140	$140	$838	1	140	$140	$838
1.2.6	Tapered Stress Joint	1	222	$222	$1,333	1	222	$222	$1,333
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	53	$53	$316	1	53	$53	$316
1.2.8	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$63	$375	6000	0	$94	$563
1.3	**Riser Tensioners**				**$4,500**				**$5,400**
1.3.1	Hydropneumatic Riser Tensioners	1	750	$750	$4,500	1	900	$900	$5,400
1.4	**Riser Installation Equipment**				**$222**				**$222**
1.4.1	Riser & Wellhead Running Tools	0.166667	222	$37	$222	0.166667	222	$37	$222
1.5	**Umbilicals**				**$648**				**$936**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$648	6500	0	$156	$936
1.6	**Intervention**				**$0**				**$0**
1.6.1	ROV intervention system & tooling	0.166667	0	$0	$0	0.166667	0	$0	$0
1.7	**Vessel Cost Penalty (Riser Tension)**	0.166667	**14925**	$2,488	**$14,925**	0.166667	**21415**	$3,569	**$21,415**
2	**Project Management**				**$0**				**$0**
2.1	AOI Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
2.2	Vendor Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
2.4	Auditing Manufacturing Sites	0.166667	0	$0	$0	0.166667	0	$0	$0
3	**Engineering**				**$0**				**$0**
3.1	System analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
3.2	Connector testing	0.166667	0	$0	$0	0.166667	0	$0	$0
3.3	Soil boring and analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
3.4	Detail engineering including tooling	0.166667	0	$0	$0	0.166667	0	$0	$0
4	**TOTAL CAPEX COSTS ($1000)**			**$5,595**	**$33,568**			**$7,350**	**$44,102**

Item No.	TLP - 12 Well Scenario Single Casing Riser	4000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost (1000$)	6000' Water Depth Quan. Per	Item Cost	Cost Per	Total Cost (1000$)
1	**Manufacture/Materials**				**$65,788**				**$86,487**
1.1	**Surface Wellhead Equipment**				**$5,814**				**$5,814**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	323	$323	$3,876	1	323	$323	$3,876
1.1.2	11" 10,000 psi Surface Wellhead	1	102	$102	$1,218	1	102	$102	$1,218
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$720	1	60	$60	$720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	**Riser Equipment**				**$20,731**				**$26,444**
1.2.1	18-3/4" external hydraulic Wellhead Connector	1	250	$250	$3,000	1	250	$250	$3,000
1.2.2	Instrumentation Joint and Equipment	1	65	$65	$786	1	65	$65	$786
1.2.3	63' Riser Joints 9 3/4" 59.2 ppf C - 95	62	14	$862	$10,342	94	14	$1,307	$15,679
1.2.4	Riser Pup Joints	1	73	$73	$880	1	73	$73	$880
1.2.5	Tensioner Joint	1	140	$140	$1,676	1	140	$140	$1,676
1.2.6	Tapered Stress Joint	1	222	$222	$2,666	1	222	$222	$2,666
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	53	$53	$631	1	53	$53	$631
1.2.8	5 1/2" Prod. Tubing 23 ppf L-80 Vam Ace	4000	0	$63	$750	6000	0	$94	$1,125
1.3	**Riser Tensioners**				**$9,000**				**$10,800**
1.3.1	Hydropneumatic Riser Tensioners	1	750	$750	$9,000	1	900	$900	$10,800
1.4	**Riser Installation Equipment**				**$222**				**$222**
1.4.1	Riser & Wellhead Running Tools	0.083333	222	$19	$222	0.083333	222	$19	$222
1.5	**Umbilicals**				**$1,296**				**$1,872**
1.5.1	Downhole Control Umbilicals	4500	0	$108	$1,296	6500	0	$156	$1,872
1.6	**Intervention**				**$0**				**$0**
1.6.1	ROV intervention system & tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
1.7	**Vessel Cost Penalty (Riser Tension)**	0.083333	**28725**	$2,394	**$28,725**	0.083333	**41335**	$3,445	**$41,335**
2	**Project Management**				**$0**				**$0**
2.1	AOI Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
2.2	Vendor Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
2.4	Auditing Manufacturing Sites	0.083333	0	$0	$0	0.083333	0	$0	$0
3	**Engineering**				**$0**				**$0**
3.1	System analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
3.2	Connector testing	0.083333	0	$0	$0	0.083333	0	$0	$0
3.3	Soil boring and analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
3.4	Detail engineering including tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
4	**TOTAL CAPEX COSTS ($1000)**			**$5,482**	**$65,788**			**$7,207**	**$86,487**

Item No.	SPAR - 6 Well Uninsulated Tubing Riser CAPEX COSTS	4000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	6000' Water Depth Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$33,023**				**$38,156**
1.1	**Surface Wellhead Equipment**				**$2,333**				**$2,333**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	309	309	$1,853	1	309	309	$1,853
1.1.2	11" 10,000 psi Surface Wellhead	1	20	20	$120	1	20	20	$120
1.1.3	Tree/Wellhead Work Platforms	1	60	60	$360	1	60	60	$360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	0	$0	1	0	0	$0
1.2	**Riser Equipment**				**$9,091**				**$9,122**
1.2.1	11"- 10k external hydraulic Wellhead Connector	1	200	200	$1,198	1	200	200	$1,198
1.2.2	Instrumentation Joint and Equipment	1	94	94	$567	1	94	94	$567
1.2.3	5-1/2" x 23 ppf Riser Joints	3200	0	47	$282	5200	0	76	$458
1.2.4	Riser Pup Joints	1	1	1	$9	1	1	1	$9
1.2.5	Keel Jt	1	398	398	$2,387	1	398	398	$2,387
1.2.6	Tapered Stress Joint	1	55	55	$330	1	55	55	$330
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	544	544	$3,266	1	520	520	$3,121
1.2.8	Stem Jts.	1	175	175	$1,052	1	175	175	$1,052
1.3	**Drilling/Workover Riser & Equipment**				**$5,383**				**$7,386**
1.3.1	11" 10k Hydraulic Connector	0.166667	200	33	$200	0.166667	200	33	$200
1.3.2	Integral Stress Jt. 13 5/8" Riser Flge Top	0.166667	235	39	$235	0.166667	235	39	$235
1.3.3	Transition Joint	0.166667	41	7	$41	0.166667	41	7	$41
1.3.4	13 3/8" o..d. Riser Jt. 63 ' Long	8.666667	39	341	$2,044	13.83333	39	544	$3,262
1.3.5	Spacer Jt.	0.166667	39	6	$39	0.166667	39	6	$39
1.3.6	Splash Zone Jt.	0.166667	43	7	$43	0.166667	43	7	$43
1.3.7	Keel Jt.	0.166667	413	69	$413	0.166667	413	69	$413
1.3.8	Keel Transition Jts. (2 EACH)	0.333333	243	81	$486	0.333333	243	81	$486
1.3.9	Riser Handling Tools	0.166667	235	39	$235	0.166667	235	39	$235
1.3.10	Riser Pup Joints	0.166667	125	21	$125	0.166667	125	21	$125
1.3.11	Syntactic Foam Buoyancy (lbs. buoyancy)	0.166667	1523	254	$1,523	0.166667	2307	385	$2,307
1.4	**Subsea Shear Ram Package**				**$1,982**				**$2,228**
1.4.1	18 3/4" 10k Wellhead Connector w /11k Top	0.166667	230	38	$230	0.166667	230	38	$230
1.4.2	11" 10k Shear Rams	0.166667	144	24	$144	0.166667	144	24	$144
1.4.3	Orientation Pin Spool	0.166667	60	10	$60	0.166667	60	10	$60
1.4.4	11" 10k Re - Entry Mandrel	0.166667	45	8	$45	0.166667	45	8	$45
1.4.5	Subsea Hydraulic Control System & Umbilical	0.166667	1170	195	$1,170	0.166667	1399	233	$1,399
1.4.6	Guide Frame and Rig Up	0.166667	246	41	$246	0.166667	263	44	$263
1.47	Valves, Studs, Nuts, Ring Gaskets	0.166667	87	15	$87	0.166667	87	15	$87
1.5	**Riser Tensioners**				**$5,305**				**$6,820**
1.5.1	Air Can Riser Tensioners (Production)	3	189	568	$3,409	4	189	758	$4,546
1.5.2	Hydro - Pneumatic Reeved Riser Tensioners (Drilling)	0.166667	1896	316	$1,896	0.166667	2275	379	$2,275
1.6	**Riser Installation Equipment**				**$607**				**$607**
1.6.1	Riser & Wellhead Running Tools	0.166666	572	95	$572	0.166666	572	95	$572
1.6.2	Bolt Tensioners	0.166666	35	6	$35	0.166666	35	6	$35
1.7	**Umbilicals**				**$1,445**				**$2,087**
1.7.1	Tree/Downhole Control Umbilicals	4500	0	$241	$1,445	6500	0	$348	$2,087
1.7.2	Umbilical Reels	1	0	$0	$0	1	0	$0	$0
1.7.3	Flying Leads/Umbilical Connectors	1	0	$0	$0	1	0	$0	$0
1.8	**Subsea Wellhead Equipment**				**$5,010**				**$5,010**
1.8.1	Subsea Tree 1 Valve & 1 Annulus Valve	1	395	395	$2,370	1	395	395	$2,370
1.8.2	Subsea Tubing Head Spool	1	375	375	$2,250	1	375	375	$2,250
1.8.3	Subsea Tubing Hanger	1	65	65	$390	1	65	65	$390
1.9	**Intervention**				**$0**				**$0**
1.9.1	ROV intervention system & tooling	0.166666	0	0	$0	0.166666	0	0	$0
2	**Vessel Cost Penalty (Riser Tension)**	**0.16666**	**1868**	311	**$1,868**	**0.16666**	**2564**	427	**$2,564**
3	**Project Management**				**$0**				**$0**
3.1	AOI Project Management	0.166666	0	0	$0	0.166666	0	0	$0
3.2	Vendor Project Management	0.166666	0	0	$0	0.166666	0	0	$0
3.3	Auditing Manufacturing Sites	0.166666	0	0	$0	0.166666	0	0	$0
4	**Engineering**				**$0**				**$0**
4.1	System analysis	0.166666	0	0	$0	0.166666	0	0	$0
4.2	Connector testing	0.166666	0	0	$0	0.166666	0	0	$0
4.3	Soil boring and analysis	0.166666	0	0	$0	0.166666	0	0	$0
4.4	Detail engineering including tooling	0.166666	0	0	$0	0.166666	0	0	$0
5	**TOTAL CAPEX COSTS ($1000)**			**$5,504**	**$33,023**			**$6,359**	**$38,156**

Item No.	SPAR 12 Well Uninsulated Tubing Riser CAPEX COSTS	4000' Water Depth				6000' Water Depth			
		Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$54,312**				**$61,253**
1.1	**Surface Wellhead Equipment**				**$4,667**				**$4,667**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	309	309	$3,707	1	309	309	$3,707
1.1.2	11" 10,000 psi Surface Wellhead	1	20	20	$240	1	20	20	$240
1.1.3	Tree/Wellhead Work Platforms	1	60	60	$720	1	60	60	$720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	0	$0	1	0	0	$0
1.2	**Riser Equipment**				**$18,183**				**$18,243**
1.2.1	11"- 10k external hydraulic Wellhead Connector	1	200	200	$2,396	1	200	200	$2,396
1.2.2	Instrumentation Joint and Equipment	1	94	94	$1,134	1	94	94	$1,134
1.2.3	5-1/2" x 23 ppf Riser Joints	3200	0	47	$564	5200	0	76	$916
1.2.4	Riser Pup Joints	1	1	1	$18	1	1	1	$18
1.2.5	Keel Jt	1	398	398	$4,774	1	398	398	$4,774
1.2.6	Tapered Stress Joint	1	55	55	$660	1	55	55	$660
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	544	544	$6,533	1	520	520	$6,241
1.2.8	Stem Jts.	1	175	175	$2,105	1	175	175	$2,105
1.3	**Drilling/Workover Riser & Equipment**				**$5,383**				**$7,386**
1.3.1	11" 10k Hydraulic Connector	0.083333	200	17	$200	0.083333	200	17	$200
1.3.2	Integral Stress Jt. 13 5/8" Riser Flge Top	0.083333	235	20	$235	0.083333	235	20	$235
1.3.3	Transition Joint	0.083333	41	3	$41	0.083333	41	3	$41
1.3.4	13 3/8" o..d. Riser Jt. 63 ' Long	4.333333	39	170	$2,044	6.916667	39	272	$3,262
1.3.5	Spacer Jt.	0.083333	39	3	$39	0.083333	39	3	$39
1.3.6	Splash Zone Jt.	0.083333	43	4	$43	0.083333	43	4	$43
1.3.7	Keel Jt.	0.083333	413	34	$413	0.083333	413	34	$413
1.3.8	Keel Transition Jts. (2 EACH)	0.166667	243	41	$486	0.166667	243	41	$486
1.3.9	Riser Handling Tools	0.083333	235	20	$235	0.083333	235	20	$235
1.3.10	Riser Pup Joints	0.083333	125	10	$125	0.083333	125	10	$125
1.3.11	Syntactic Foam Buoyancy (lbs. buoyancy)	0.083333	1523	127	$1,523	0.083333	2307	192	$2,307
1.4	**Subsea Shear Ram Package**				**$1,982**				**$2,228**
1.4.1	18 3/4" 10k Wellhead Connector w /11k Top	0.083333	230	19	$230	0.083333	230	19	$230
1.4.2	11" 10k Shear Rams	0.083333	144	12	$144	0.083333	144	12	$144
1.4.3	Orientation Pin Spool	0.083333	60	5	$60	0.083333	60	5	$60
1.4.4	11" 10k Re - Entry Mandrel	0.083333	45	4	$45	0.083333	45	4	$45
1.4.5	Subsea Hydraulic Control System & Umbilical	0.083333	1170	97	$1,170	0.083333	1399	117	$1,399
1.4.6	Guide Frame and Rig Up	0.083333	246	20	$246	0.083333	263	22	$263
1.47	Valves, Studs, Nuts, Ring Gaskets	0.083333	87	7	$87	0.083333	87	7	$87
1.5	**Riser Tensioners**				**$8,714**				**$11,366**
1.5.1	Air Can Riser Tensioners (Production)	3	189	568	$6,818	4	189	758	$9,091
1.5.2	Hydro - Pneumatic Reeved Riser Tensioners (Drilling)	0.083333	1896	158	$1,896	0.083333	2275	190	$2,275
1.6	**Riser Installation Equipment**				**$607**				**$607**
1.6.1	Riser & Wellhead Running Tools	0.083333	572	48	$572	0.083333	572	48	$572
1.6.2	Bolt Tensioners	0.083333	35	3	$35	0.083333	35	3	$35
1.7	**Umbilicals**				**$2,889**				**$4,173**
1.7.1	Tree/Downhole Control Umbilicals	4500	0	$241	$2,889	6500	0	$348	$4,173
1.7.2	Umbilical Reels	0.083333	0	$0	$0	0.083333	0	$0	$0
1.7.3	Flying Leads/Umbilical Connectors	1	0	$0	$0	1	0	$0	$0
1.8	**Subsea Wellhead Equipment**				**$10,020**				**$10,020**
1.8.1	Subsea Tree 1 Valve & 1 Annulus Valve	1	395	395	$4,740	1	395	395	$4,740
1.8.2	Subsea Tubing Head Spool	1	375	375	$4,500	1	375	375	$4,500
1.8.3	Subsea Tubing Hanger	1	65	65	$780	1	65	65	$780
1.9	**Intervention**				**$0**				**$0**
1.9.1	ROV intervention system & tooling	0.083333	0	0	$0	0.083333	0	0	$0
2	**Vessel Cost Penalty (Riser Tension)**	0.083333	**1868**	156	**$1,868**	0.083333	**2564**	214	**$2,564**
3	**Project Management**				**$0**				**$0**
3.1	AOI Project Management	0.083333	0	0	$0	0.083333	0	0	$0
3.2	Vendor Project Management	0.083333	0	0	$0	0.083333	0	0	$0
3.3	Auditing Manufacturing Sites	0.083333	0	0	$0	0.083333	0	0	$0
4	**Engineering**				**$0**				**$0**
4.1	System analysis	0.083333	0	0	$0	0.083333	0	0	$0
4.2	Connector testing	0.083333	0	0	$0	0.083333	0	0	$0
4.3	Soil boring and analysis	0.083333	0	0	$0	0.083333	0	0	$0
4.4	Detail engineering including tooling	0.083333	0	0	$0	0.083333	0	0	$0
5	**TOTAL CAPEX COSTS ($1000)**			**$4,526**	**$54,312**			**$5,104**	**$61,253**

Item No.	TLP - 6 Well Uninsulated Tubing Riser CAPEX COSTS	4000' Water Depth				6000' Water Depth			
		Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$29,989**				**$36,325**
1.1	**Surface Wellhead Equipment**				**$2,333**				**$2,333**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	309	$309	$1,853	1	309	$309	$1,853
1.1.2	11" 10,000 psi Surface Wellhead	1	20	$20	$120	1	20	$20	$120
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$360	1	60	$60	$360
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	**Riser Equipment**				**$3,407**				**$3,583**
1.2.1	11"- 10k external hydraulic Wellhead Connector	1	200	$200	$1,198	1	200	$200	$1,198
1.2.2	Instrumentation Joint and Equipment	1	65	$65	$393	1	65	$65	$393
1.2.3	5-1/2" x 23 ppf Riser Joints	4000	0	$59	$352	6000	0	$88	$528
1.2.4	Riser Pup Joints	1	1	$1	$9	1	1	$1	$9
1.2.5	Keel Jt	1	137	$137	$820	1	137	$137	$820
1.2.6	Tapered Stress Joint	1	55	$55	$330	1	55	$55	$330
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	51	$51	$305	1	51	$51	$305
1.3	**Drilling/Workover Riser & Equipment**				**$4,931**				**$6,967**
1.3.1	11" 10k Hydraulic Connector	0.166667	200	$33	$200	0.166667	200	$33	$200
1.3.2	Integral Stress Jt. 13 5/8" Riser Flge Top	0.166667	235	$39	$235	0.166667	235	$39	$235
1.3.3	Transition Joint	0.166667	41	$7	$41	0.166667	41	$7	$41
1.3.4	13 3/8" o..d. Riser Jt. 63 ' Long	10	39	$393	$2,358	15.33333	39	$603	$3,616
1.3.5	Spacer Jt.	0.166667	29	$5	$29	0.166667	29	$5	$29
1.3.6	Splash Zone Jt.	0.166667	43	$7	$43	0.166667	43	$7	$43
1.3.7	Keel Jt.	0.166667	171	$29	$171	0.166667	171	$29	$171
1.3.8	Keel Transition Jts. (2 EACH)	0.166667	235	$39	$235	0.166667	235	$39	$235
1.3.9	Riser Handling Tools	0.166667	35	$6	$35	0.166667	35	$6	$35
1.3.10	Riser Pup Joints	0.166667	125	$21	$125	0.166667	125	$21	$125
1.3.11	Syntactic Foam Buoyancy (lbs. buoyancy)	0.166667	1459	$243	$1,459	0.166667	2238	$373	$2,238
1.4	**Subsea Shear Ram Package**				**$1,982**				**$2,228**
1.4.1	18 3/4" 10k Wellhead Connector w /11k Top	0.166667	230	$38	$230	0.166667	230	$38	$230
1.4.2	11" 10k Shear Rams	0.166667	144	$24	$144	0.166667	144	$24	$144
1.4.3	Orientation Pin Spool	0.166667	60	$10	$60	0.166667	60	$10	$60
1.4.4	11" 10k Re - Entry Mandrel	0.166667	45	$8	$45	0.166667	45	$8	$45
1.4.5	Subsea Hydraulic Control System & Umbilical	0.166667	1170	$195	$1,170	0.166667	1399	$233	$1,399
1.4.6	Guide Frame and Rig Up	0.166667	246	$41	$246	0.166667	263	$44	$263
1.47	Valves, Studs, Nuts, Ring Gaskets	0.166667	87	$15	$87	0.166667	87	$15	$87
1.5	**Riser Tensioners**			$0	**$3,275**			$0	**$3,750**
1.5.1	Air Can Riser Tensioners (Production)	1	450	$450	$2,700	1	500	$500	$3,000
1.5.2	Hydro - Pneumatic Reeved Riser Tensioners (Dr	0.166667	575	$96	$575	0.166667	750	$125	$750
1.6	**Riser Installation Equipment**				**$222**				**$222**
1.6.1	Riser & Wellhead Running Tools	0.166667	222	$37	$222	0.166667	222	$37	$222
1.7	**Umbilicals**				**$1,445**				**$2,087**
1.7.1	Tree/Downhole Control Umbilicals	4500	0	$241	$1,445	6500	0	$348	$2,087
1.7.2	Umbilical Reels	1	0	$0	$0	1	0	$0	$0
1.7.3	Flying Leads/Umbilical Connectors	1	0	$0	$0	1	0	$0	$0
1.8	**Subsea Wellhead Equipment**				**$5,010**				**$5,010**
1.8.1	Subsea Tree 1 Valve & 1 Annulus Valve	1	395	$395	$2,370	1	395	$395	$2,370
1.8.2	Subsea Tubing Head Spool	1	375	$375	$2,250	1	375	$375	$2,250
1.8.3	Subsea Tubing Hanger	1	65	$65	$390	1	65	$65	$390
1.9	**Intervention**				**$0**				**$0**
1.9.1	ROV intervention system & tooling	1	0	$0	$0	1	0	$0	$0
2	**Vessel Cost Penalty (Riser Tension)**	**0.166667**	**7385**	**$1,231**	**$7,385**	**0.166667**	**10145**	**$1,691**	**$10,145**
3	**Project Management**				**$0**				**$0**
3.1	AOI Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
3.2	Vendor Project Management	0.166667	0	$0	$0	0.166667	0	$0	$0
3.3	Auditing Manufacturing Sites	0.166667	0	$0	$0	0.166667	0	$0	$0
4	**Engineering**				**$0**				**$0**
4.1	System analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
4.2	Connector testing	0.166667	0	$0	$0	0.166667	0	$0	$0
4.3	Soil boring and analysis	0.166667	0	$0	$0	0.166667	0	$0	$0
4.4	Detail engineering including tooling	0.166667	0	$0	$0	0.166667	0	$0	$0
5	**TOTAL CAPEX COSTS ($1000)**			$4,998	**$29,989**			$6,054	**$36,325**

Item No.	TLP - 12 Well Uninsulated Tubing Riser CAPEX COSTS	4000' Water Depth				6000' Water Depth			
		Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)	Quan. Per Well	Item Cost (1000$)	Cost Per Well (1000$)	Total Cost (1000$)
1	**Manufacture/Materials**				**$50,683**				**$60,297**
1.1	**Surface Wellhead Equipment**				**$4,667**				**$4,667**
1.1.1	Surface Tree 5" 10,000 psi discrete valves	1	309	$309	$3,707	1	309	$309	$3,707
1.1.2	Surface Wellhead	1	20	$20	$240	1	20	$20	$240
1.1.3	Tree/Wellhead Work Platforms	1	60	$60	$720	1	60	$60	$720
1.1.4	60' x 5" 10,000 psi Flowline (ft.)	1	0	$0	$0	1	0	$0	$0
1.2	**Riser Equipment**				**$6,813**				**$7,165**
1.2.1	11"- 10k external hydraulic Wellhead Connector	1	200	$200	$2,396	1	200	$200	$2,396
1.2.2	Instrumentation Joint and Equipment	1	65	$65	$786	1	65	$65	$786
1.2.3	5-1/2" x 40' x 23 ppf Insulated Riser Joints	4000	0	$59	$705	6000	0	$88	$1,057
1.2.4	Riser Pup Joints	1	1	$1	$18	1	1	$1	$18
1.2.5	9 5/8" Tensioner Joint	1	137	$137	$1,639	1	137	$137	$1,639
1.2.6	Tapered Stress Joint	1	55	$55	$660	1	55	$55	$660
1.2.7	Hvy. Wall, Transition, Spacer Jts./Well	1	51	$51	$610	1	51	$51	$610
1.3	**Drilling/Workover Riser & Equipment**				**$4,931**				**$6,967**
1.3.1	11" 10k Hydraulic Connector	0.083333	200	$17	$200	0.083333	200	$17	$200
1.3.2	Integral Stress Jt. 13 5/8" Riser Flge Top	0.083333	235	$20	$235	0.083333	235	$20	$235
1.3.3	Transition Joint	0.083333	41	$3	$41	0.083333	41	$3	$41
1.3.4	13 3/8" o..d. Riser Jt. 63 ' Long	5	39	$197	$2,358	7.666667	39	$301	$3,616
1.3.5	Spacer Jt.	0.083333	29	$2	$29	0.083333	29	$2	$29
1.3.6	Splash Zone Jt.	0.083333	43	$4	$43	0.083333	43	$4	$43
1.3.7	Tensioner Jt.	0.083333	171	$14	$171	0.083333	171	$14	$171
1.3.8	Riser Handling Tools	0.083333	235	$20	$235	0.083333	235	$20	$235
1.3.9	Bolt Tensioners	0.083333	35	$3	$35	0.083333	35	$3	$35
1.3.10	Riser Pup Joints	0.083333	125	$10	$125	0.083333	125	$10	$125
1.3.11	Syntactic Foam Buoyancy	0.083333	1459	$122	$1,459	0.083333	2238	$186	$2,238
1.4	**Subsea Shear Ram Package**				**$1,982**				**$2,228**
1.4.1	18 3/4" 10k Wellhead Connector w /11k Top	0.083333	230	$19	$230	0.083333	230	$19	$230
1.4.2	11" 10k Shear Rams	0.083333	144	$12	$144	0.083333	144	$12	$144
1.4.3	Orientation Pin Spool	0.083333	60	$5	$60	0.083333	60	$5	$60
1.4.4	11" 10k Re - Entry Mandrel	0.083333	45	$4	$45	0.083333	45	$4	$45
1.4.5	Subsea Hyd. Control System & Umbilical	0.083333	1170	$97	$1,170	0.083333	1399	$117	$1,399
1.4.6	Guide Frame and Rig Up	0.083333	246	$20	$246	0.083333	263	$22	$263
1.47	Valves, Studs, Nuts, Ring Gaskets	0.083333	87	$7	$87	0.083333	87	$7	$87
1.5	**Riser Tensioners**			$0	**$5,975**			$0	**$6,750**
1.5.1	Hydropneumatic Riser Tensioners (Prod.)	1	450	$450	$5,400	1	500	$500	$6,000
1.5.2	Hydropneumatic Riser Tensioners (Drilling)	0.083333	575	$48	$575	0.083333	750	$63	$750
1.6	**Riser Installation Equipment**				**$222**				**$222**
1.6.1	Riser & Wellhead Running Tools	0.083333	222	$19	$222	0.083333	222	$19	$222
1.7	**Umbilicals**				**$2,889**				**$4,173**
1.7.1	Tree/Downhole Control Umbilicals	4500	0	$241	$2,889	6500	0	$348	$4,173
1.7.2	Umbilical Reels	0.083333	0	$0	$0	0.083333	0	$0	$0
1.7.3	Flying Leads/Umbilical Connectors	1	0	$0	$0	1	0	$0	$0
1.8	**Subsea Wellhead Equipment**				**$10,020**				**$10,020**
1.8.1	Subsea Tree 1 Valve & 1 Annulus Valve	1	395	$395	$4,740	1	395	$395	$4,740
1.8.2	Subsea Tubing Head Spool	1	375	$375	$4,500	1	375	$375	$4,500
1.8.3	Subsea Tubing Hanger	1	65	$65	$780	1	65	$65	$780
1.9	**Intervention**				**$0**				**$0**
1.9.1	ROV intervention system & tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
2	**Vessel Cost Penalty (Riser Tension)**	0.083333	**13185**	**$1,099**	**$13,185**	0.083333	**18105**	**$1,509**	**$18,105**
3	**Project Management**				**$0**				**$0**
3.1	AOI Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
3.2	Vendor Project Management	0.083333	0	$0	$0	0.083333	0	$0	$0
3.4	Auditing Manufacturing Sites	0.083333	0	$0	$0	0.083333	0	$0	$0
4	**Engineering**	0.083333			**$0**	0.083333			**$0**
4.1	System analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
4.2	Connector testing	0.083333	0	$0	$0	0.083333	0	$0	$0
4.3	Soil boring and analysis	0.083333	0	$0	$0	0.083333	0	$0	$0
4.4	Detail engineering including tooling	0.083333	0	$0	$0	0.083333	0	$0	$0
5	**TOTAL CAPEX COSTS**			$4,224	**$50,683**			$5,025	**$60,297**

6.3.2 Subsea Well System CAPEX

Varialbe Input Values			Subsea Systems CAPEX	Cost Summary, $1000	
				Conventional	Horizontal
Number of Wells	6				
Water Depth, feet	4000	TOTAL	Subsea System - Materials	$102,217	$101,923
Pipeline Size, inches	12	Conventional	Subsea System - Installation	$93,040	$93,040
Pipeline Length, miles	35	214,786	One Well - Materials	$3,255	$2,570
Infield Extension, miles	5	Horizontal	Infield Extension - Materials	$20,499	$20,499
		210,383	Infield Extension - Installation	$15,749	$15,749

Conventional Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	100
Tubing Hanger Spool	225
Tree (Vertical 4" x 2" -1OK GLL, Pod/Choke)	2,500
Tree Cap	150
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$3,255
Subsea System Hardware - Production mode	**Cost, $1000**
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,500
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
THRT / BOP Spanner (2)	400
Workover Controls Umbilical (Elec / Hyd)	600
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	200
ROV Tools -Misc (Estimated)	1,000
Completion Riser / Workover Controls (Rental)	250
Workover Riser (5"X2"riser, 45 ft. joints) ($12,000/joint)	1,067
Surface Tree Controls	60
Subtotal	$10,977
Pipelines And Umbilicals - Materials	**Cost, $1000**
Flowline (2) (based on diameter and length)	70312
Flowline PLEM	600
Umbilical & Elec + Hydraulic (based on length)	20328
Subtotal	$91,240
Pipelines And Umbilicals - Inatallation	**Cost, $1000**
Flowline Installation (2) (based on diameter and length)	70312
Umbilical Installation (based on length)	20328
Manifold Installation	2000
Flowline Jumpers (2) Installation	400
Subtotal	$93,040

Horizontal Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	130
Horizontal Tree (Vertical 4" x 2" -1OK GLL, include: Pod/Choke)	2,000
Wireline Plugs (Internal) and Isolation Sleeve	100
Tree Cap - Internal Plug Design	60
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$2,570
Subsea System Hardware - Production mode	**Cost, $1000**
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,000
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
Completion Riser / Workover Controls (Option)	500
THRT / Subsea test Tree / - Est.	400
WO Umbilical / Reel (Elec / Hyd) $150/ft	600
Workover Riser (Premium Tubing, 45 ft. joints)	133
Surface Tree Controls	1,000
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	150
ROV Tooling packages	1,000
Subtotal	$10,683
Infield Extension PL & Umbilicals - Materials	**Cost, $1000**
Flowline (2) (based on diameter and length)	10045
Flowline PLEM (2-lines, 2-ends) = 4*600	2400
Masnifold - multiple well (foundation base + manifold)	2000
Umbilical & Elec + Hydraulic (based on length)	2904
Umbilical PLEM - Hydraulic (2-ends)	1200
Umbilical PLEM - Electrical (2-ends)	1200
Hydraulic Distribution Module	750
Subtotal	$20,499
Infield Extension PL & Umbilicals - Installation	**Cost, $1000**
Flowline Etension Installation (2) (based on diameter & length)	10045
Umbilical Extension Installation (based on length)	2904
Manifold Installation	2000
Flowline Jumpers (4) Installation	800
Subtotal	$15,749

Varialbe Input Values			Subsea Systems CAPEX	Cost Summary, $1000	
				Conventional	Horizontal
Number of Wells	6				
Water Depth, feet	6000	TOTAL	Subsea System - Materials	$103,050	$102,290
Pipeline Size, inches	12	Conventional	Subsea System - Installation	$93,040	$93,040
Pipeline Length, miles	35	215,620	One Well - Materials	$3,255	$2,570
Infield Extension, miles	5	Horizontal	Infield Extension - Materials	$20,499	$20,499
		210,750	Infield Extension - Installation	$15,749	$15,749

Conventional Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	100
Tubing Hanger Spool	225
Tree (Vertical 4" x 2" -1OK GLL, Pod/Choke)	2,500
Tree Cap	150
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$3,255
Subsea System Hardware - Production mode	**Cost, $1000**
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,500
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
THRT / BOP Spanner (2)	400
Workover Controls Umbilical (Elec / Hyd)	900
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	200
ROV Tools -Misc (Estimated)	1,000
Completion Riser / Workover Controls (Rental)	250
Workover Riser (5"X2"riser, 45 ft. joints) ($12,000/joint)	1,600
Surface Tree Controls	60
Subtotal	$11,810
Pipelines And Umbilicals - Materials	**Cost, $1000**
Flowline (2) (based on diameter and length)	70312
Flowline PLEM	600
Umbilical & Elec + Hydraulic (based on length)	20328
Subtotal	$91,240
Pipelines And Umbilicals - Inatallation	**Cost, $1000**
Flowline Installation (2) (based on diameter and length)	70312
Umbilical Installation (based on length)	20328
Manifold Installation	2000
Flowline Jumpers (2) Installation	400
Subtotal	$93,040

Horizontal Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	130
Horizontal Tree (Vertical 4" x 2" -1OK GLL, include: Pod/Choke)	2,000
Wireline Plugs (Internal) and Isolation Sleeve	100
Tree Cap - Internal Plug Design	60
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$2,570
Subsea System Hardware - Production mode	**Cost, $1000**
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,000
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
Completion Riser / Workover Controls (Option)	500
THRT / Subsea test Tree / - Est.	400
WO Umbilical / Reel (Elec / Hyd) $150/ft	900
Workover Riser (Premium Tubing, 45 ft. joints)	200
Surface Tree Controls	1,000
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	150
ROV Tooling packages	1,000
Subtotal	$11,050
Infield Extension PL & Umbilicals - Materials	**Cost, $1000**
Flowline (2) (based on diameter and length)	10045
Flowline PLEM (2-lines, 2-ends) = 4*600	2400
Masnifold - multiple well (foundation base + manifold)	2000
Umbilical & Elec + Hydraulic (based on length)	2904
Umbilical PLEM - Hydraulic (2-ends)	1200
Umbilical PLEM - Electrical (2-ends)	1200
Hydraulic Distribution Module	750
Subtotal	$20,499
Infield Extension PL & Umbilicals - Installation	**Cost, $1000**
Flowline Etension Installation (2) (based on diameter & length)	10045
Umbilical Extension Installation (based on length)	2904
Manifold Installation	2000
Flowline Jumpers (4) Installation	800
Subtotal	$15,749

Varialbe Input Values	
Number of Wells	12
Water Depth, feet	4000
Pipeline Size, inches	12
Pipeline Length, miles	35
Infield Extension, miles	5

TOTAL	
Conventional	270,564
Horizontal	262,050

Subsea Systems CAPEX	Cost Summary, $1000	
	Conventional	Horizontal
Subsea System - Materials	$102,217	$101,923
Subsea System - Installation	$93,040	$93,040
One Well - Materials	$3,255	$2,570
Infield Extension - Materials	$20,499	$20,499
Infield Extension - Installation	$15,749	$15,749

Conventional Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	100
Tubing Hanger Spool	225
Tree (Vertical 4" x 2" -1OK GLL, Pod/Choke)	2,500
Tree Cap	150
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$3,255

Subsea System Hardware - Production mode	Cost, $1000
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,500
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
THRT / BOP Spanner (2)	400
Workover Controls Umbilical (Elec / Hyd)	600
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	200
ROV Tools -Misc (Estimated)	1,000
Completion Riser / Workover Controls (Rental)	250
Workover Riser (5"X2"riser, 45 ft. joints) ($12,000/joint)	1,067
Surface Tree Controls	60
Subtotal	$10,977

Pipelines And Umbilicals - Materials	Cost, $1000
Flowline (2) (based on diameter and length)	70312
Flowline PLEM	600
Umbilical & Elec + Hydraulic (based on length)	20328
Subtotal	$91,240

Pipelines And Umbilicals - Inatallation	Cost, $1000
Flowline Installation (2) (based on diameter and length)	70312
Umbilical Installation (based on length)	20328
Manifold Installation	2000
Flowline Jumpers (2) Installation	400
Subtotal	$93,040

Horizontal Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	130
Horizontal Tree (Vertical 4" x 2" -1OK GLL, include: Pod/Choke)	2,000
Wireline Plugs (Internal) and Isolation Sleeve	100
Tree Cap - Internal Plug Design	60
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$2,570

Subsea System Hardware - Production mode	Cost, $1000
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,000
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
Completion Riser / Workover Controls (Option)	500
THRT / Subsea test Tree / - Est.	400
WO Umbilical / Reel (Elec / Hyd) $150/ft	600
Workover Riser (Premium Tubing, 45 ft. joints)	133
Surface Tree Controls	1,000
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	150
ROV Tooling packages	1,000
Subtotal	$10,683

Infield Extension PL & Umbilicals - Materials	Cost, $1000
Flowline (2) (based on diameter and length)	10045
Flowline PLEM (2-lines, 2-ends) = 4*600	2400
Masnifold - multiple well (foundation base + manifold)	2000
Umbilical & Elec + Hydraulic (based on length)	2904
Umbilical PLEM - Hydraulic (2-ends)	1200
Umbilical PLEM - Electrical (2-ends)	1200
Hydraulic Distribution Module	750
Subtotal	$20,499

Infield Extension PL & Umbilicals - Installation	Cost, $1000
Flowline Etension Installation (2) (based on diameter & length)	10045
Umbilical Extension Installation (based on length)	2904
Manifold Installation	2000
Flowline Jumpers (4) Installation	800
Subtotal	$15,749

Varialbe Input Values	
Number of Wells	12
Water Depth, feet	6000
Pipeline Size, inches	12
Pipeline Length, miles	35
Infield Extension, miles	5

TOTAL	
Conventional	271,397
Horizontal	262,417

Subsea Systems CAPEX	Cost Summary, $1000	
	Conventional	Horizontal
Subsea System - Materials	$103,050	$102,290
Subsea System - Installation	$93,040	$93,040
One Well - Materials	$3,255	$2,570
Infield Extension - Materials	$20,499	$20,499
Infield Extension - Installation	$15,749	$15,749

Conventional Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	100
Tubing Hanger Spool	225
Tree (Vertical 4" x 2" -1OK GLL, Pod/Choke)	2,500
Tree Cap	150
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$3,255

Subsea System Hardware - Production mode	Cost, $1000
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,500
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
THRT / BOP Spanner (2)	400
Workover Controls Umbilical (Elec / Hyd)	900
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	200
ROV Tools -Misc (Estimated)	1,000
Completion Riser / Workover Controls (Rental)	250
Workover Riser (5"X2"riser, 45 ft. joints) ($12,000/joint)	1,600
Surface Tree Controls	60
Subtotal	$11,810

Pipelines And Umbilicals - Materials	Cost, $1000
Flowline (2) (based on diameter and length)	70312
Flowline PLEM	600
Umbilical & Elec + Hydraulic (based on length)	20328
Subtotal	$91,240

Pipelines And Umbilicals - Inatallation	Cost, $1000
Flowline Installation (2) (based on diameter and length)	70312
Umbilical Installation (based on length)	20328
Manifold Installation	2000
Flowline Jumpers (2) Installation	400
Subtotal	$93,040

Horizontal Subsea Tree - Materials

One Well Hardware - Production mode	Cost, $1000
Tubing Hanger	130
Horizontal Tree (Vertical 4" x 2" -1OK GLL, include: Pod/Choke)	2,000
Wireline Plugs (Internal) and Isolation Sleeve	100
Tree Cap - Internal Plug Design	60
Flying Leads Hydraulic / Electrical - sets	80
Well Jumper (6" Hardpiped)	200
Subtotal	$2,570

Subsea System Hardware - Production mode	Cost, $1000
E/H Mux Controls (Topside HPU, MCS)	1,200
Umbilical PLEM - Hydraulic	600
Electrical PLEM -	600
Manifold - 6 well (foundation base + manifold)	2,000
Flowline jumper	300
HDM (Hydraulic Distribution Module)	750
Misc / Test Eq. / Shipping Skids / Handling Eq.	750
Completion Riser / Workover Controls (Option)	500
THRT / Subsea test Tree / - Est.	400
WO Umbilical / Reel (Elec / Hyd) $150/ft	900
Workover Riser (Premium Tubing, 45 ft. joints)	200
Surface Tree Controls	1,000
Workover Controls - HPU / Jumpers / etc.	700
TJ/ surface tree / pups	150
ROV Tooling packages	1,000
Subtotal	$11,050

Infield Extension PL & Umbilicals - Materials	Cost, $1000
Flowline (2) (based on diameter and length)	10045
Flowline PLEM (2-lines, 2-ends) = 4*600	2400
Masnifold - multiple well (foundation base + manifold)	2000
Umbilical & Elec + Hydraulic (based on length)	2904
Umbilical PLEM - Hydraulic (2-ends)	1200
Umbilical PLEM - Electrical (2-ends)	1200
Hydraulic Distribution Module	750
Subtotal	$20,499

Infield Extension PL & Umbilicals - Installation	Cost, $1000
Flowline Etension Installation (2) (based on diameter & length)	10045
Umbilical Extension Installation (based on length)	2904
Manifold Installation	2000
Flowline Jumpers (4) Installation	800
Subtotal	$15,749

7 RISK EXPENDITURES, RISKEX

7.1 Frequency Assessment

This section describes the reliability and fault tree theory used in the study of the Lifetime Costs of Subsea Production Systems in the determination of the frequency of an uncontrolled release. This theory forms the basis of a methodology for the assessment of the risks associated with Lifetime Costs of Subsea Production Systems.

The objectives of this section are to:

- Outline the reliability theory behind the study.
- Outline the fault tree theory behind the study.
- Document the fault tree logic used to assess the Lifetime Costs of Subsea Production Systems.
- Describe the use of failure data, fault tree logic and methodology to assess the Lifetime Costs of alternative well systems.

7.1.1 Introduction to Reliability Analysis

Reliability analysis as basis for system optimization involves an iterative process of reliability assessment and improvement, and the relationship between these two aspects is important. In some cases the assessment shows that the system is sufficiently reliable. In other cases the reliability is found to be inadequate, but the assessment work reveals ways in which the reliability can be improved. It is generally agreed that the value of reliability assessment lies not only in the figure obtained for system reliability, but in the discovery of the ways in which reliability can be improved.

7.1.2 Definition of Reliability

Reliability can be defined as the probability that an item will perform a required function under stated conditions for a stated period of time. This definition brings out several important points about reliability.

- It is a probability.
- It is a function of time.
- It is a function of defined conditions.
- It is a function of the definition of failure.

Part of this reliability definition relies upon the definition of probability. This probability is based upon the concept of relative frequency. The concept of relative frequency states that if an experiment is performed “n” times and if the event A occurs on “n_a” of these occasions, then the probability P(A) of event A is:

$$P(A) = \lim_{n \to \infty} \frac{n_a}{n}$$

This definition of reliability is the one which is most widely used in engineering. In particular, it is this definition which is implied in the estimation of probability from field failure data.

Another definition of probability is degree of belief. It is the numerical measure of the belief which a person has that the event will occur. Often this corresponds to the relative frequency of the event. However, this is not always so, for several reasons. One is that the relative frequency data available to the individual may be limited or non-existent. Another is that even if the individual has such data, he/she may have other information which causes him/her to think that the data are not the whole truth. The individual may doubt the applicability of the data to the case under consideration, or he/she may have information which suggests that the situation has changed since these data were collected. Personal probability was cast into disrespect during the nineteenth century when science was believed to be the absolute truth, because, with this definition the results will depend upon the person solving the problem. However, this objection to subjectivity has changed since then and been countered quite effectively. Sometimes this is the only source of information available.

There are several branches of probability theory which attempt to accommodate subjective/personal probabilities. These include ranking techniques which give the numerical encoding of judgements on the probability ranking of items, and Bayesian methods, which allow probabilities to be modified in the light of additional information.

7.1.3 Probability Theory Basics

Since the theory of reliability is based upon probability theories and statistical methods it is appropriate to give a brief treatment of some basic probability relationships. It is these basic probability expressions which underlie much of the fault tree theory described later.

7.1.3.1 Probability of Unions

The probability of an event X, which occurs if any of the events A_i occur, is given as:

$$P(X) = P(\bigcup_{i=1}^{n} A_i) \tag{7.1}$$

i.e., the statistical union of these events.

If there are two events the probability that X occurs is given by:

$$P(X) = P(A_1) + P(A_2) - P(A_1 \cap A_2) \tag{7.2}$$

If the events are mutually exclusive the above equation simplifies to:

$$P(X) = \sum_{i=1}^{n} P(A_1) \tag{7.3}$$

In general the above equation's relationship to equation (8.1) is as follows:

$$P(\bigcup_{i=1}^{n} A_i) \leq \sum_{i=1}^{n} P(A_i) \tag{7.4}$$

For events which are not mutually exclusive but of low probability the error in using equation (8.3) is small. Equation number (8.3) is sometimes referred to as the "rare approximation."

7.1.3.2 Joint Probability

The probability of an event X, which occurs only if all the "n" events A_i occur, is

$$P(X) = P(A_i ... A_n) = P(\bigcap_{i=1}^{n} A_i) \tag{7.5}$$

i.e., the statistical intersection of these events.

7.1.3.3 Conditional Probability and Marginal Probabilities

The probability of an event X which occurs if the event A occurs in one experiment and the event B occurs in a second experiment where the event A depends upon the event B is

$$P(X) = P(AB) = P(A \mid B)P(B) = P(B \mid A)P(A) \tag{7.6}$$

$P(A \mid B)$ is the conditional probability of A given B. This is also referred to as "Bayes Theorem".

Marginal probabilities can be obtained from conditional probabilities:

$$P(X) = \sum_{i=1}^{n} P(B \mid A_i)P(A_i) = P(B) \tag{7.7}$$

$P(B)$ is the marginal probability of the event.

7.1.3.4 Independence

If event A and B are independent

$$P(AB) = P(A \mid B)P(B) = P(A)P(B) \tag{7.8}$$

which means that $P(A \mid B) = P(A)$.

The probability of an event X which occurs only if all "n" events A_i occur are given by equation (8.5). If all n events are independent:

$$P(X) = P(A_i ... A_n) = \prod_{i=1}^{n} P(A_i) \tag{7.9}$$

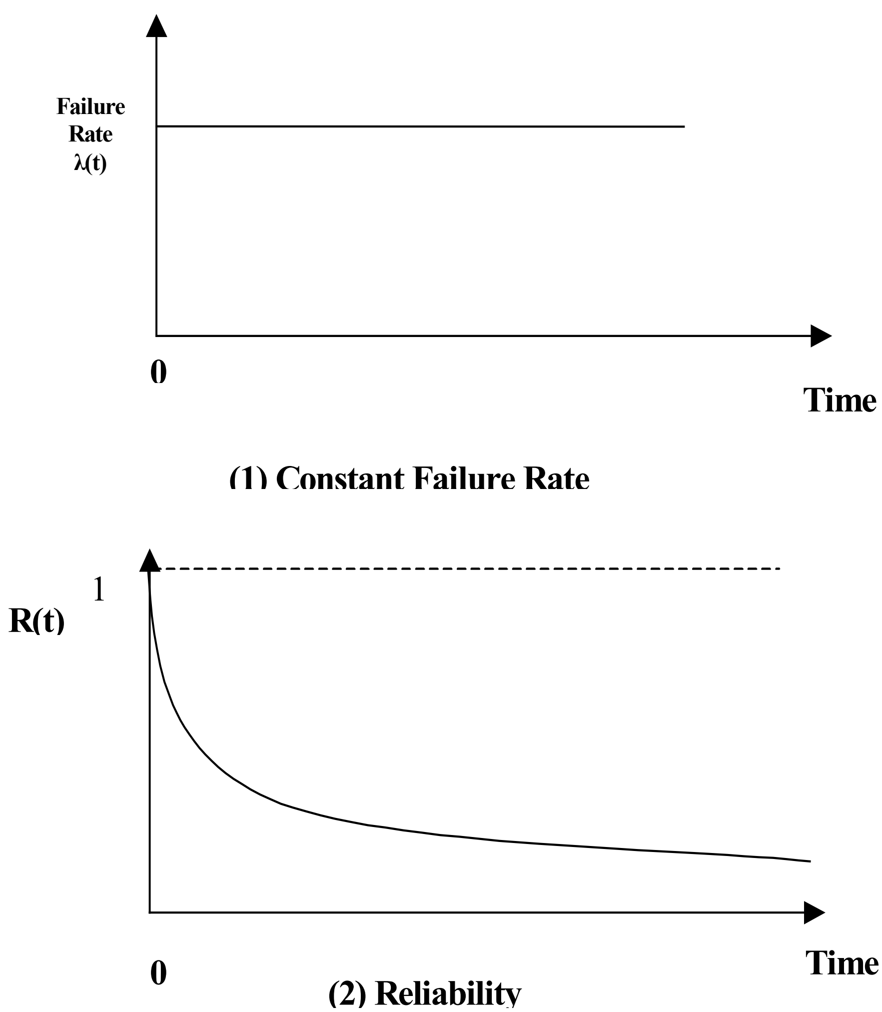
7.1.4 Reliability Distributions

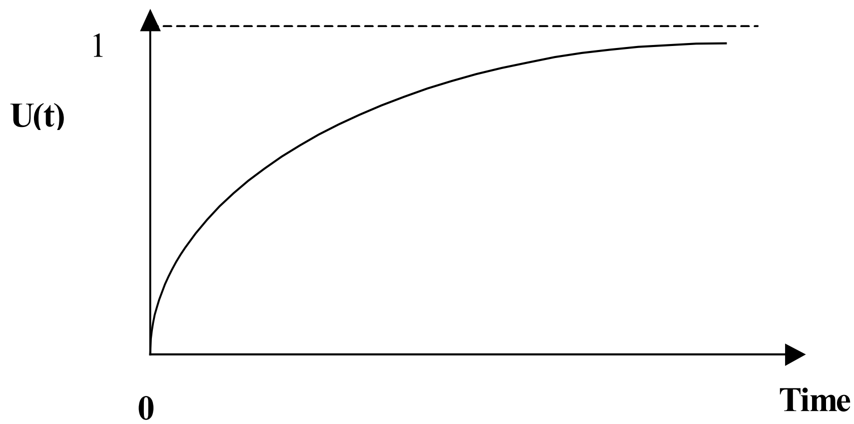
There are several statistical distributions which are fundamental in work on reliability. Some of these statistical distributions are used to model the failure rate (λ) of systems, equipment, or components. Examples of such distributions are Weibull, Log-normal, and Negative Exponential. The most common distribution used is the negative exponential distribution. This is a widely used distribution and the easiest one to treat mathematically. It assumes that the failure rate of the component (λ) is constant. The form of the exponential distribution is:

$$R(t) = \exp(-\lambda t) \tag{7.10}$$

In graphical terms the negative exponential distribution parameters look as illustrated in Figure 7.1. The figure also shows the reliability and unreliability of the negative exponential distribution as a function of time.

Figure 7.1: Exponential Failure Distribution





(3) Unreliability

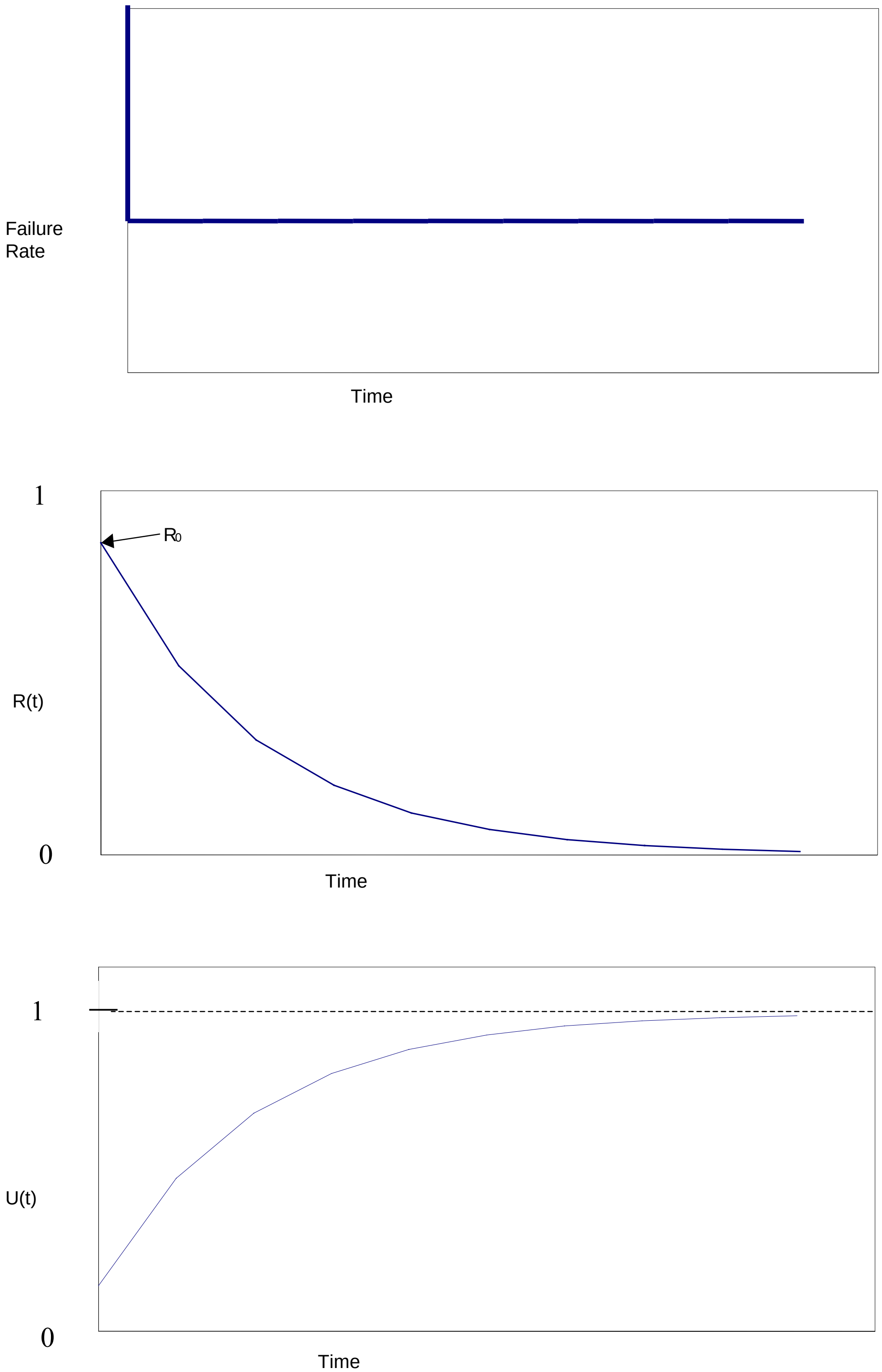
The assumption that the failure rate of the component is constant is normally made in the absence of other information, and is based upon the premise that the failures are distributed randomly. That is the model is appropriate where failure of an item is not due to start-up problems (infant mortality) or to deterioration as a result of the effects of wear. Most completion component reliability data sources (statistical failure data for completion components is sparse) are based on exponentially distributed failure times.

It is common knowledge that completion components often fail shortly after installation, if they fail. As a broad example of this, there is a predominance of uncontrolled leaks to environment during the relatively short time interval of intervention activities rather than during the prolonged production period. In this study "installation failure probabilities", R_0, (time independent) are used in combination with the exponential distribution (time dependent) to better describe the "lifetime" reliability of the completion components and systems. The modeled reliability is described by the following equation:

$$R(t) = R_0 * \exp(-\lambda t) \qquad (7.11)$$

The reliability and unreliability functions versus time, when using this definition of reliability, are shown in Figure 7.2.

Figure 7.2: Installation Failure Probability and Negative Exponential Distribution



Finally, it must be emphasized that there will always be uncertainties related to the relevancy of the statistical model applied when a system failure performance is modeled as a stochastic phenomenon.

7.1.4.1 The Bath Tub Curve

"Life time" reliability of systems of equipment components is often illustrated by the "Bath Tub" curve.

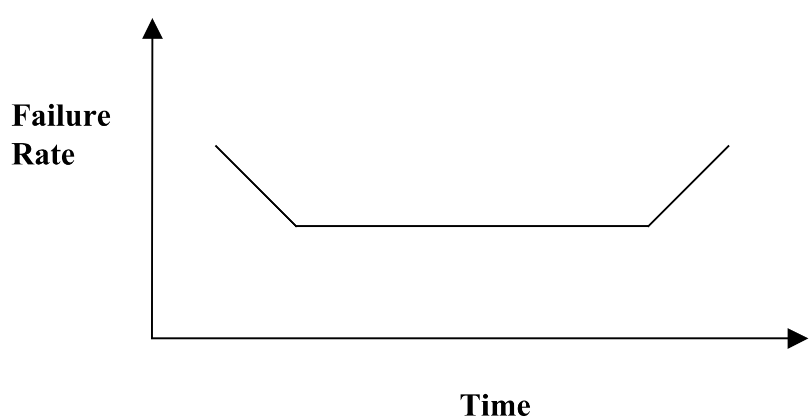
From experience it has been illustrated that the failure behavior of equipment exhibits three stages. Initially in "Early Life" the failure rate is high, "Infant Mortality", then it declines during "Normal Operation" to a constant rate, and then finally rises again as deterioration sets in, "wear out." For many types of equipment, and particularly electronic equipment, the failure rate has been found to form a bathtub curve. The same is believed to apply for most mechanical components.

Early failures, "Infant mortality," are usually due to such factors as defective equipment, incorrect installation, etc. These early failures dominate the reliability of the completion systems in the well intervention mode and are also sometimes significant in the long-term production mode.

The "constant" or so-called "random" failure is often caused by random fluctuations of load, which may exceed the design strength. Both experiment and detailed failure data analysis of systems have showed a constant failure characteristic where a number of components each individually exhibit different failure distribution. When these individual distributions are aggregated together, the overall failure distribution of the system will appear random (constant).

As the life of the component increases eventually "wear out" will dominate. This is where the failure rate increases (rapidly) with time. For the completion system subject to evaluation the modeling of the "wear out" phenomena was not considered significant over a field life of 10 years or so.

Figure 7.3: The Classical Bath Tub Curve



7.1.4.2 Mean Time Between Failure

Other terms that are use to measure or quantify reliability is the "Mean Time To Failure" (MTTF) and the "Mean Time Between Failures" (MTBF). The most widely used is probably the MTBF. This parameter is defined as the total operating time divided by the number of failures, and only has meaning when components, equipment or systems can be repaired. When the time to failure is exponentially distributed, the relationship between the MTBF of the equipment (or the system) and the equipment (or system) failure rate is simply:

$$\text{Failure Rate } (\lambda) = \frac{1}{MTBF} \tag{7.11}$$

The MTBF is the mean of the failure distribution regardless of its form.

7.1.5 Reliability of Some Standard Systems

In this section, the reliability of two standard systems is considered: a "series" system and a "parallel" system. The following explains how these configurations are handled mathematically.

7.1.5.1 Series Systems

In a series system the system fails to function if any one of the items in series fails to perform its required function, over the specified period of time. It is not implied that the components are necessarily laid out physically in a series configuration. The probability theory presented earlier states that the reliability of such a system is the product of the reliabilities R_i of the components.

$$R_{system} = \prod_{i=1}^{n} R_i \tag{7.12}$$

In other words: "A chain is no stronger than its weakest link". In the Lifetime Costs of Subsea Production Systems Study the reliability of the completion string can be modeled as a series system of tubing joints and other downhole completion components.

When using installation probabilities and the negative exponential distribution (the failure rates of the components are constant λ_i) the reliability of individual components is:

$$R_i = R_0 * \exp(-\lambda_i t) = R_0 * \exp(-\frac{t}{MTBF}) \tag{7.13}$$

and therefore the reliability of the system of "n" components is:

$$R_{system} = \prod_{i=1}^{n} R_{0/i} * \exp(-\lambda_i t) \tag{7.14}$$

7.1.5.2 Parallel Systems

A parallel system is one which fails to operate only if all its components fail to operate. Again it is not implied that the components are necessarily laid out physically in a parallel configuration. The reliability of a parallel system is:

$$\mathrm{R} = 1 - \prod_{i=1}^{n}(1 - R_i) \tag{7.15}$$

where $R_i = R_{0/i} * \exp(-\lambda_i t)$

Since parallel configurations incorporate redundancy, they are also referred to as "parallel redundant systems." For parallel systems where the negative exponential distribution applies the reliability is given by:

$$R_{system} = 1 - \prod_{i=1}^{n}[1 - R_0 * \exp(-\lambda_i t)] \tag{7.16}$$

For parallel systems there is no simple general relationship between the system failure rate and the component failure rates. It should also be noted that the reliability of a parallel system does not follow an exponential distribution.

In the Lifetime Costs of Subsea Production Systems Study parallel/redundant configurations can be seen in the barrier philosophies used on each of the systems.

7.1.6 Introduction to Fault Tree Analysis

This section presents the details regarding the construction, evaluation, and quantification of the fault trees that are employed by the study of Lifetime Costs of Subsea Production Systems. The fault tree methodology was chosen as the primary means of computing the frequency of an uncontrolled release to the environment as fault trees are well suited to estimate the probability or frequency of a single event that is a result of a number of causal events. The loss of kill weight fluid, in combination with the loss of the BOP barrier resulting in an uncontrolled leak during workover is a typical example of such an event. In the following paragraphs, firstly the theory of fault trees is described, then the thought process behind the construction of the fault trees is discussed along with example fault trees. The fault trees, which combine the production and intervention modes, are also shown. Finally, the reliability data applied for each of the fault tree components are presented. The results of the analysis are presented in subsequent sections.

7.1.6.1 Fault Tree Theory

A fault tree is a logic diagram that displays the connections between a potential system failure (TOP event) and the reasons for this event. The basic elements of a fault tree may be classed as:

(1) Top Event
(2) Base Events
(3) Intermediate Events
(4) Logic Gates.

Top Event
The Top Event is the event of interest. In the case of the Lifetime Costs of Subsea Production Systems this Top Event is an uncontrolled release to the environment.

Base Events
A Base event represents the failure of individual system components.

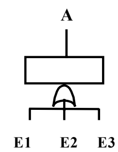
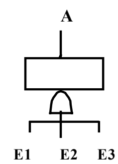
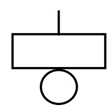
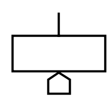
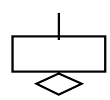
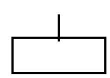
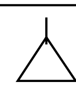
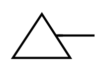
Intermediate Events
The intermediate events are events which form links between the Top Event and the Base Event. In the Lifetime Costs of Subsea Production Systems Study an example of an intermediate event is "Loss of Primary Containment."

Logic Gates
Logic gates provide the logical connections between Base Events, Intermediate Events and the Top Event. A table of the different logic gate symbols and their description is shown in Table 7.1.

"Base Events" represent component failures and is therefore considered to exist in one of two states. These states are "operating" as required (un-failed) or in a "failed" state.

The fault tree construction always starts with the TOP event. The analyst must then identify all fault events that are the immediate, necessary and sufficient causes that result in the TOP event. These causes are connected to the top event via a logic gate. The first level is referred to as the top structure, and the causes are taken to be failures in the prime modules. The method is deductive and is carried out repeatedly by asking, "What are the reasons for…?", until all failure events have been developed to the required level of resolution.

Table 7.1: Explanation of Fault Tree Symbols

	SYMBOL		DESCRIPTION
LOGIC GATES	"OR" gate		The OR-gate indicates that the output event A occurs if any of the input events Ei occurs.
	"AND" gate		The AND-gate indicates that the output event A occurs only when all the input events Ei occurs simultaneously.
INPUT EVENTS	"BASIC" event		The Basic event represents a basic equipment fault or failure that requires no further development into more basic faults or failures.
	"HOUSE" event		The House event represents a condition or an event which is TRUE (ON) or FALSE (OFF) (not true).
	"UNDEVELOPED" event		The Undeveloped event represents a fault event that is not examined further because information is unavailable or because its consequence is insignificant.
DESCRIPTION OF STATE	"COMMENT" rectangle		The Comment rectangle is for supplementary information.
TRANSFER SYMBOLS	"TRANSFER" out		The Transfer **out** symbol indicates that the fault tree is developed further at the occurrence of the corresponding Transfer **in** symbol.
	"TRANSFER" in		

A fault tree provides valuable information about possible combinations of fault events that can result in a critical failure (TOP event) of the system. Such a combination of fault events is called a cut set and is defined as follows:

> *A cut set in a fault tree is a set of Base Events whose (simultaneous) occurrence ensures that the TOP event occurs. A cut set is minimal if the set cannot be reduced without loosing its status as a cut set.*

A summary of the advantages and disadvantages of the Fault Tree Method are summarized in Table 7.2.

Table 7.2: Advantages and Disadvantages of the Fault Tree Method

Advantages	Disadvantages
Identifies and records systematically the logical fault paths from a specific effect, back to the prime causes.	May lead to very large trees if the analysis is extended in depth.
Deals with parallel, redundant or alternative fault paths.	The same event may appear in different parts of the tree, leading to some confusion.
Deals with most forms of combinatorial events and some forms of dependencies.	Does not represent the transition paths between the states of any one event.
Deals with systems which have several cross-linked sub-systems.	Requires a separate fault tree for each TOP event; inter-relationships between trees may require careful consideration.
Provide for fairly easy manipulation of the fault paths to give minimal logical models.	The prime causes identified by the fault tree that leads to the TOP event are related only to the specific outcome being analyzed.
The technique has the ability to identify the combinations of basic equipment failures, human errors that can lead to the top event. This allows the analyst to focus on the significant basic causes of the accident and identify preventative measures to reduce the likelihood of the event.	Primarily directed towards fault or failure analysis and does not deal effectively with complex repair and maintenance strategies or general availability analysis.
Identify major contributors to the TOP event from a probability point of view.	--
It allows the identification of common mode or common cause failures which may not be apparent when considering sub-systems in isolation.	--
"Searches" for possible causes of an end effect which may not have been foreseen.	--

7.1.6.2 Definition of Top Events and Boundary Conditions

The critical event to be analyzed is called the TOP event, this is normally some undesired event. It is very important that the TOP event is given clear and unambiguous definition. The description of the TOP event should always answer the questions: *what*, *where* and *when.*

<u>Example:</u>

What: Describes what type of critical event is occurring, e.g. loss of both primary and secondary isolation barriers resulting in uncontrolled well flow.

Where: Describes where the critical event occurs. In this study the uncontrolled well flow could be at the surface, at the subsea wellhead or in the riser zone.

When: Describes when the critical event occurs, e.g. during either production or intervention mode.

To get a consistent analysis, it has also been important to:

- Define the initial conditions. What is the operational state of the system for the mode subject to evaluation?
- Define the level of resolution. How far down in detail should we go to identify potential reasons for a failed state? For the purpose of this FTA the level of detail is defined by the barrier and seal failure analysis.

7.1.6.3 Calculations – Basic Formulas

Assuming *independent components/events* the calculation rules for the logic gates using probability rules are as follows:

Table 7.3: Fault Tree Basic Formula

Gate	Formula	Description
AND	P(A)*P(B)	Output fault occurs if all of the input events occur
OR	P(A) + P(B) – P(A)*P(B)	Output fault occurs if at least one of the input events occur

7.1.7 Well Control Barriers

The risk of loss of well control is ever present with any hydrocarbon producing facility. For deepwater risers new components are introduced, existing well components are used in more novel applications, and well dynamic loads become a factor not encountered in shallow water platform well design.

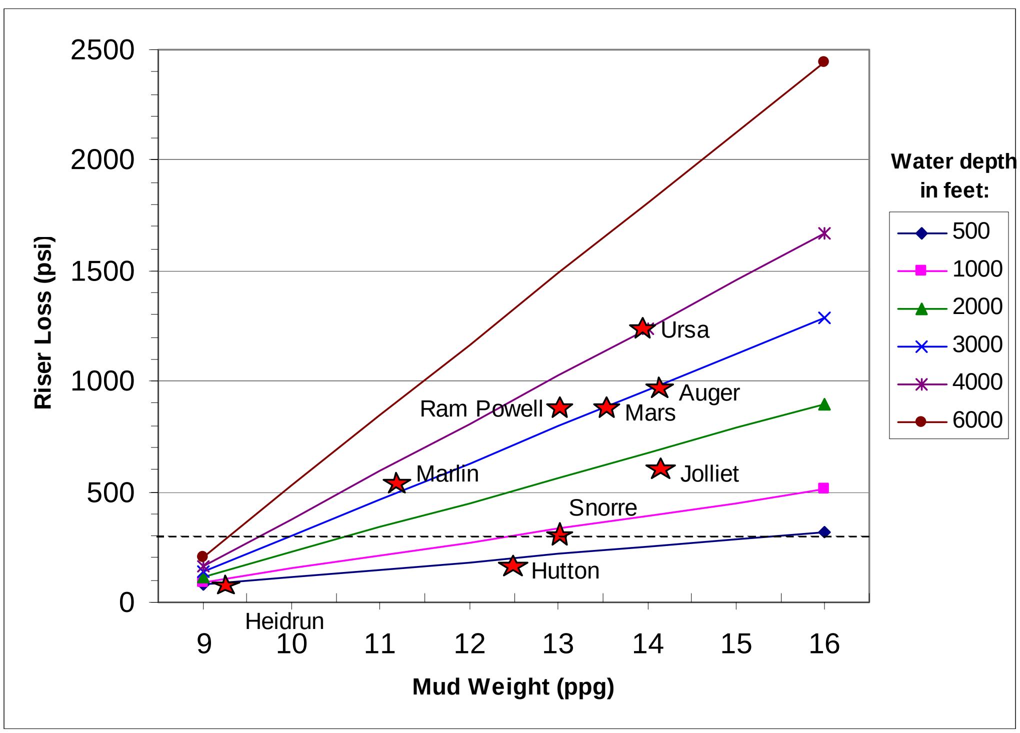
Failures of well system components are usually due to a combination of otherwise minor problems and events. Failures rarely occur due to a component being overloaded by excessive pressure or because an unexpected storm causes excessive riser stresses. Most well system leaks result from a combinations of such factors as a small defect in a seal, insignificant damage in sealing surface, less than perfect seal installation and inability to detect a small leak when field testing. Often these failures are attributed to “human error” because such failures are theoretically avoidable by “perfect” management and operations. Multiple redundancy must be designed into a well control system to provide necessary reliability because it is impossible, or at least impractical, to avoid all possible failures.

A fundamental principle in risk management is that a safety system must be designed so that the failure of a single component will not cause a system failure. The oil industry has always used this philosophy in well design. For example, a tubing string and packer is installed in the production casing to contain, control, and transport the produced fluid from the reservoir to the surface. In the event that a leak occurs in the tubing string or packer, the production casing controls the well until the tubing-packer system can be safely replaced. The mud column hydrostatic pressure provides the primary well control barrier during drilling and well interventions (with completion equipment out of the hole). The riser/casing and BOP system provides the second barrier in the event of a “kick” when the mud column pressure is inadequate to contain formation pressure. The mud column in a riser exerts greater pressure than surrounding seawater pressure since mud density is higher than seawater density. A riser leak or disconnected riser allows mud column pressure to equalize with surrounding seawater pressure. This difference in mud column pressure and seawater pressure is termed “riser loss”. In deep water this “riser loss” typically amounts to 200 to 2000 psi depending on water depth and mud weight. When “riser loss” is several hundred psi or more, a leaking connection or small hole worn in the riser will soon erode to become a large hole as mud is forced from the riser.

In shallow water there is sometimes enough excess mud column pressure, termed “riser margin”, to contain formation pressure when the riser leaks or is disconnected. The “riser margin” typically is 300 to 700 psi for drilling operations and 100 to 300 psi for completion and workover operations. When “riser margin” is greater than “riser loss” the riser/casing and BOP system provides one barrier and the mud column provides an independent second well control barrier. The mud column and riser system provide independent well control barriers only when water depth is shallow and/or formation pressure gradients are low. The Hutton, Snorre and Heidrun platforms are examples where these barriers are independent due to comparatively shallow water depths and low to moderate mud weight requirements.

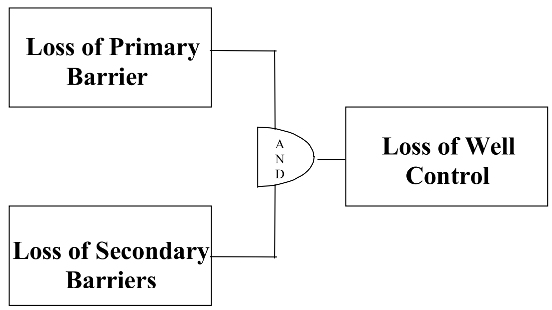
In deep water when high mud weights are required to contain formation pressure the “riser loss” is greater than “riser margin”. A riser leak or disconnected riser results in the simultaneous loss of both well control barriers. Figure 7.4 illustrates the potential for this problem on typical floating production facilities that are already installed or about to be installed. Most platforms that are installed in deeper water and that require higher mud weights use a dual casing riser system. In these cases, dual independent barriers can be provided without a mud column during well interventions.

Figure 7.4: Possible Riser Loss versus Mud Weight



When trying to combine individual barrier reliabilities into an overall system reliability, a fault tree approach can be used. This is illustrated in Figure 7.5. Loss of well control happens if loss of the primary barrier is accompanied by loss of the secondary barrier.

Figure 7.5: Generic Fault Tree for a Well Control System

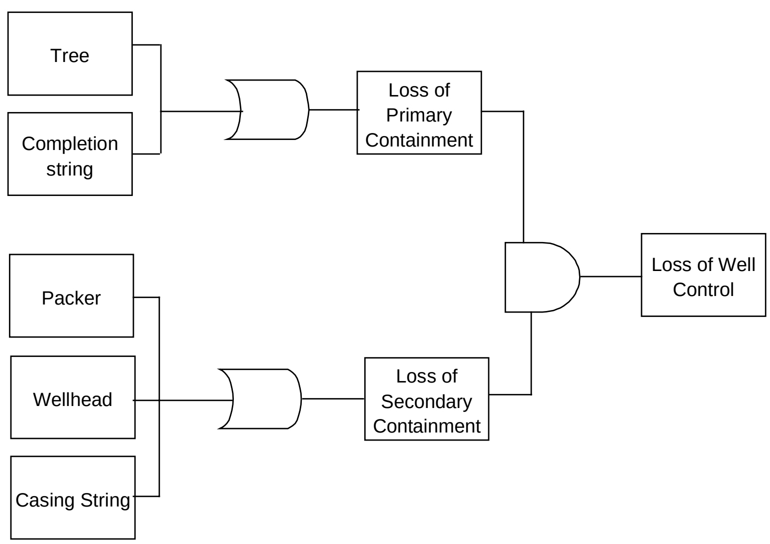


During regular production the SCSSV[1], the production tubing and the packer provide the primary barrier function. The secondary barriers include the casing, riser system, the connector seals, stress joint, etc.

In the drilling or well intervention mode, the primary containment mechanism is the well bore fluid. For instance, during well interventions, the secondary barriers include the riser, casing, BOP, tubing plug (if installed), packer (if installed), etc.

7.1.8 Fault Tree Development

Figure 7.4: Generic Fault Tree for a Well Control System



[1] The Surface Controlled Subsurface Safety Valve (SCSSV) also represents a secondary barrier in case of a leak above SCSSV.

In the development of fault trees for the Lifetime Costs of Subsea Production Systems Study the basic thought process is as illustrated in Figure 7.4. Fault trees are used to symbolically represent the configuration of well system components to facilitate the mathematical representation of the overall well system reliability based on individual completion component reliabilities.

A fundamental principal of well control is that at least two independent barriers must be established to contain the well. When a failure occurs in one well control barrier, the backup barrier prevents a blowout. It is impractical to increase the reliability of a single barrier enough to equal the reliability of an ordinary two-barrier system.

A well control barrier can be a single component or a series of connected components. Unperforated casing provides a single barrier to the flow of reservoir fluid. A cement retainer and/or cement plug in the casing provides a barrier. In the production mode, where oil flows up the tubing string and a mud column is no longer present to contain the well, the two barrier system consists of (a) the packer, tubing string, and tree and (b) casing/riser, the wellhead and BOPs. Numerous completion components comprise each of these barriers.

A subsurface safety valve, SCSSV, may be considered a barrier for the portion of the tubing string downstream from the SCSSV. Completion fluid in the casing-to-tubing annulus may also provide backup in the event of a failure of one of these primary safety systems.

7.1.8.1 Components of the Fault Tree

For the study of the Lifetime Costs of Subsea Production Systems the following components were identified to represent the barriers during production and intervention operations.

Fault Tree Components: Production Mode

The following defines the primary containment system and the barrier system during production mode:

<u>*Primary Containment System*</u>

A) Production tubing above the SCSSV.

The primary containment components are:

1. Tubing itself.
2. SCSSV.
3. Side Pocket Mandrel.
4. Chemical Injection Port.
5. X-mas Tree (including valves).
6. Tubing spool production stab seal (for Tubing Riser System).

B) Production Tubing below the SCSSV.

The primary components of the containment system below the SCSSV are:

1. Packer.
2. Anchor Tubing Seal Assembly.

3. Tubing itself.
4. Side Pocket Mandrel
5. Cement Retainer.

Secondary Containment System

A) Tubing Hanger System:

1. Tubing Hanger Seals.
2. Tree Connector Gasket.
3. X-over Sub Stab Seals.
4. Tree Connector Test Valve.

B) Casing System

1. Various casing strings.
2. Casing Hanger Seals.

C) Wellhead Connector System:

1. Casing Hanger Pack-off.
2. Tubing Hanger Spool Gasket.
3. Isolation Stab.

Fault Tree Components: Well Interventions

Well interventions, in the current study, include initial installation, uphole recompletion, sidetracking operation, and unplanned workovers (repairs). The fault tree used in the production mode was modified to accommodate all the intervention operations. If a particular component is not applicable for any given step of the operation, this particular component of the fault tree was disabled. The fault tree used to calculate the frequency or uncontrolled leaks during well intervention mode is a little more complicated than the Fault Tree used for the production mode. The overall logic of the fault tree is shown in Figure 7.6. Table 7.5 defines the primary containment system and the barrier system during well interventions.

Figure 7.6: Workover/Intervention Fault Tree

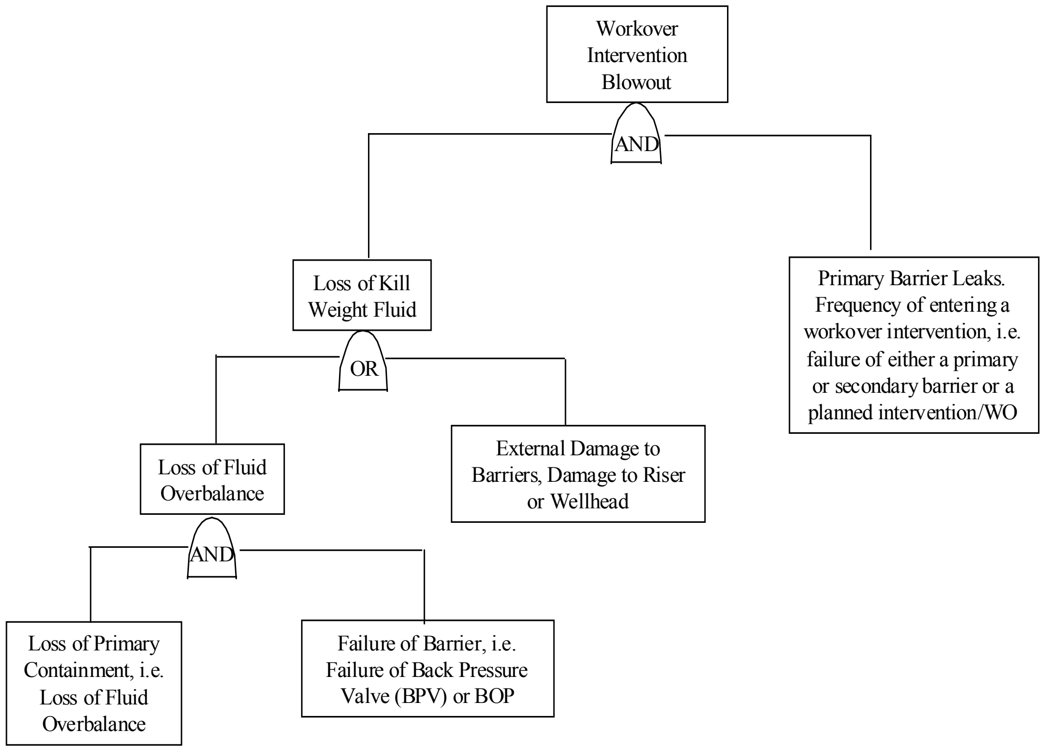


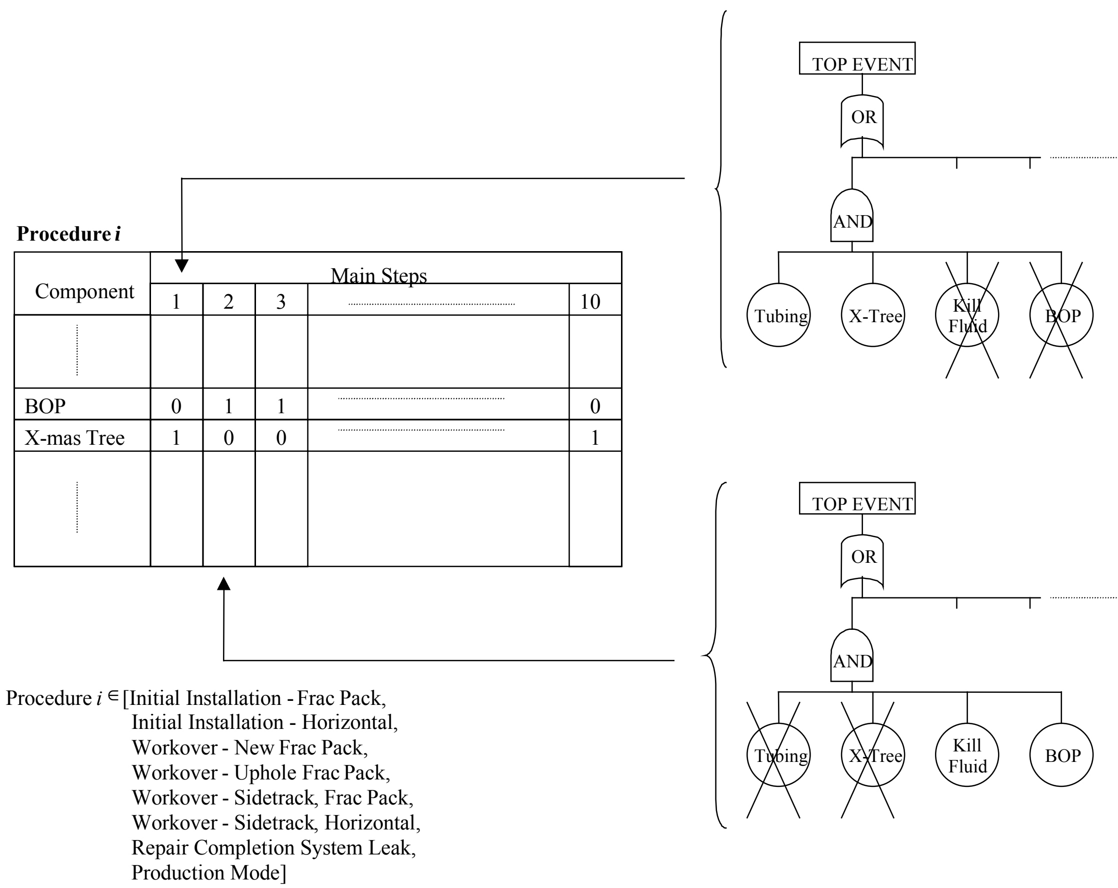
Table 7.5: Components of Workover/Intervention Fault Tree

Primary Containment/barrier	Components in the Fault Tree
Primary Containment System	1. Fluid Overbalance (kill fluid) 2. Completion System (riser, casing) 3. Packer and Tubing Plug (if installed) 4. Cement Job
Barrier System*	1. SCSSV (if used) 2. Xmas Tree 3. BOP 4. Riser 5. Casing (Sub-mudline) 6. Subsea Shear Ram 7. Drilling Riser

* Note that depending on the source of the primary leak, some of these barriers will be inapplicable.

To analyze the reliability of the different workover/intervention operations, the individual workover/intervention procedures were reviewed. This review enabled each workover intervention operation to be divided into a number of steps. Representing each step of a workover/intervention by a separate fault tree and calculating the top event probability would be extremely time consuming. To avoid this problem, within each well intervention or workover operation, similar steps were grouped together. 3-10 main steps could then represent any given well intervention operation. Within each main step, the barriers were assumed to be the same. For each system considered in this study (Conventional Tree and Horizontal Tree) one fault tree was developed with ALL the barriers represented (for both normal production and workover operations). However, not all the barriers are active at the same time, and a separate coding system was developed to allow the fault tree to be dynamically changed over time. Barriers in place in the system were either enabled (1) or disabled (0). This concept is illustrated in Figure 7.7. Principle drawings for the 2 fault trees developed are given in Figure 7.8 to Figure 7.7. The detailed drawings of the fault tree are given in the attachment to this section.

Figure 7.7: Fault Tree Principle Followed to Allow the Overall Fault Tree to Change Dynamically with Time



To allow the same fault tree to be used for both the production mode and the intervention mode the calculation rules used for the logic gates were made conditional on the status of the Base events. For instance, representing a disabled component/barrier with a probability equal to zero (i.e. component can not fail), necessitated a special treatment of the AND gates. This is best illustrated by an example:

Consider an AND gate with two Base events (1 and 2) having a failure probability of P_1 *and* P_2 *respectively. By applying the standard calculation rules, the output from the AND gate will then be* $P_{AND} = P_1 \text{ x } P_2 = 0$ *if either* P_1 *or* P_2 *is equal to zero (or both). The following conditional calculation rule was adopted to solve this issue (assuming that one Base event is enabled for the whole period of time considered):*

IF $(P_2 = 0)$ *THEN*

$P_{AND} = P_1$

ELSE

$P_{AND} = P_1 x P_2$

END IF

It can be easily verified that the OR gates do not need special treatment when representing a disabled component/barrier with a probability equal to zero.

Figure 7.8: Fault Tree Structure – Conventional Tree

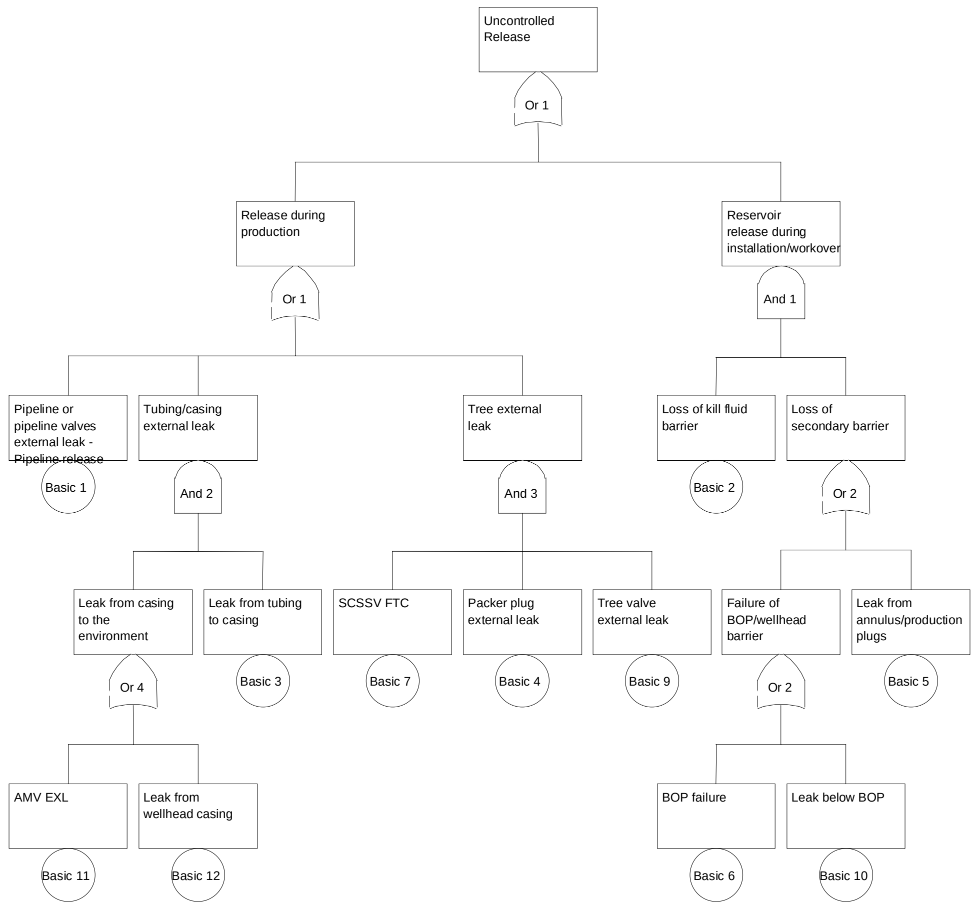
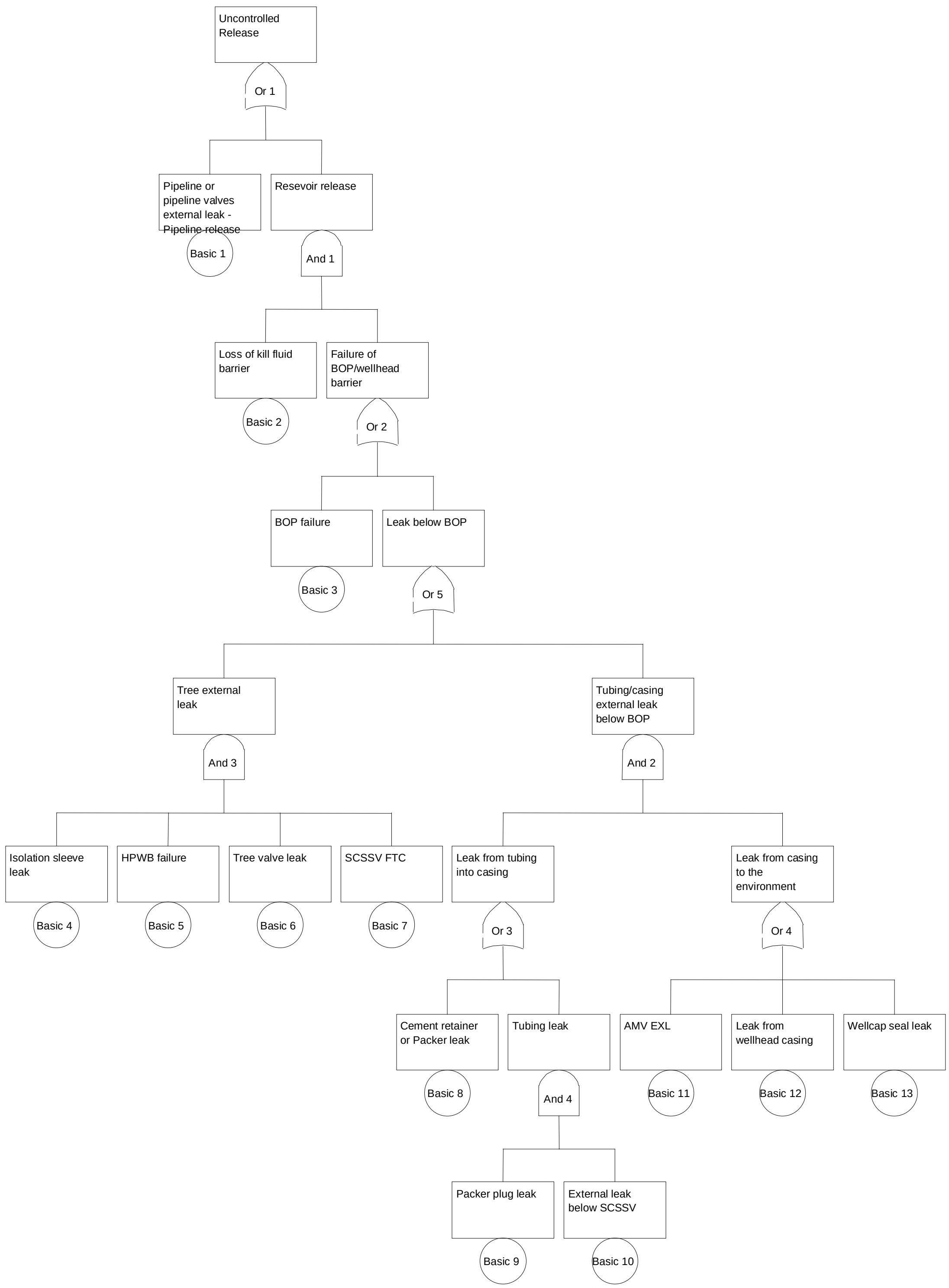


Figure 7.9: Fault Tree Structure – Horizontal Tree



7.1.8.2 Reliability Modeling of Unrevealed Failures

In classical fault tree analysis the failure performance of an equipment/system is normally based on a failure frequency for the primary unit and a failure probability for the associated protective device (barrier, back-up, etc.). The protective device is subjected to either "revealed" failures or "unrevealed" failures (or a combination of both). Revealed failures will normally manifest themselves to the operators of the system thus allowing a repair action to be initiated. Unrevealed failures as their name implies only manifest themselves either when the protective system is called upon to act or when identified by some form of proof test.

The SCSSV is a typical example of such a device, and the SCSSVs are required to be "proof tested" by Government Legislation on a regular basis. All other seals and barriers will be tested when installed and when the actual demand arises or when tested during a well intervention activity. An example of such a seal/barrier system is the tubing hanger seals. It is essential that these are performing their function when the primary barrier system fails. Therefore, while in the *producing mode* the majority of the well system components in the secondary and tertiary barrier system will generally suffer from "unrevealed" failure modes. This assumption is based upon the fact that the pressure tests, etc. used when these systems are installed should provide adequate indication of installation failures. In the *intervention mode* the failure modes of such systems can either be "revealed" or "unrevealed" depending upon the equipment. The critical protective system will be subjected to some form of proof test if possible. If a revealed failure occurs (i.e., BOP stack test failure) then the intervention is stopped and the failure repaired. For unrevealed failures the actual failure is likely only to be identified when the component or sub system is required to operate. The way that such failures are handled in the fault tree analysis is to calculate the probability of failure of the protective system to "operate on demand." This probability is calculated using the following formula:

$$\text{Probability of Failure on Demand (P)} = \frac{\lambda\tau}{2} \tag{7.18}$$

where P is the probability of failure, λ is the failure rate for the unrevealed ("hidden") failures and τ is the test interval[2].

To model the probability of an uncontrolled leak to the environment during normal production the approach described above is adopted. The number of workovers carried out during a 10 year period is (5+4+4+5+2+2+5=27) for the 12-well case and (3+2+2+2+1+1+2=13) for the 6-well case[3]. For a 10-year production time (not including time spent on workovers) this means that one well will on average be worked over approximately every 3.1 year.

[2] Valid only when $\tau \ll$ MTBF

[3] An anlysis of workovers on the Norwegian Sector prior to 1989 showed an average of 1 per 10 well years for a relatively low average age of well. A DNV internal database which forms the basis for QRAs recommends an average workover rate of 1 per 7 well years. However, the workover rate for typical oil wells is believed to be higher than for gas wells. Sand control problems in the Gulf of Mexico require more frequent workovers. High rate wells typically deplete quickly, requiring more frequent workovers.

The probability of failure of both the primary barrier (PB) and secondary barrier (SB) during normal production is estimated as:

$$P(PB \cap SB) = \frac{10}{3.1} \mathrm{P_{PB}}(3.1 \text{ year}) \cdot \mathrm{P_{SB}}(\frac{3.1}{2} \text{ year}) \tag{7.19}$$

Where

$$\begin{aligned} \mathrm{P_{PB}} &= 1 - e^{\lambda_{PB} \cdot 3.1 \text{ year}} \\ \mathrm{P_{SB}} &= 1 - e^{\lambda_{SB} \cdot 3.1 \text{ year}/2} \approx \frac{1}{2} \lambda_{SB} \cdot 3.1 \text{ year} \end{aligned} \tag{7.20}$$

λ_{PB} is the failure rate of the primary barrier (failures per year) and λ_{SB} is the failure rate of the secondary barrier (failures per year).

7.1.8.3 Reliability Modeling of Early Life Failures (Installation Failure Probability)

In the "Early Life" failure case which may be the dominant mode of failure in many of the components used in the Subsea Production Systems Study, it is important to take into account the influence of human factors in installing/operating the equipment. It is not the aim or objectives of this study to perform a detailed "Human Factors" analysis of installation and operating procedures, but it is acknowledged that the study should take account of the influence of the human interaction with components in some manner.

From research into "Early Life" failures, evidence indicates that the causes of such failures can be grouped under three headings.

1) Those failures which result in failure of newly commissioned equipment,
2) Those which result in failure of equipment which has been operating for some time, and
3) Those associated with start up and shut down stresses in equipment.

In the case of the Subsea Production Systems Study it is possible to identify cases for all three regimes. Examples would include premature failure of a downhole gauge due to incorrect installation, or design deficiency or manufacturing defects. For Case 2 an example would be a premature uncontrolled leak in a tubing joint due to such causes as manufacturing defect, excessive corrosion, etc., and for Case 3 it could be failure of a downhole safety valve "to open" after the first regulatory test.

The research also indicates that the causes of such "Early Life" failures can be attributed to the following factors:

1) Incorrect design assumption, i.e. well fluid composition incorrect.
2) Incorrect design and specification, i.e. too high a flow rate.
3) Incorrect selection of materials or material defect, i.e. metallurgy brittle.
4) Incorrect manufacturing process.
5) Incorrect installation procedure.
6) Incorrect commissioning and initial operation, i.e. incorrect start-up procedure.

From the same research the failure in "Early Life" of equipment which has a longer operating history centers on the quality of the maintenance and includes:

1) Incorrect fault identification
2) Incorrect repair techniques
3) Incorrect replacement parts
4) Incorrect reassemble and alignment
5) Dirty working conditions
6) Disturbance of other parts in the system.

Underlying these latter causes of "Early Life" failures are two fundamental causes. One is conducting unnecessary preventative maintenance and the other is inadequate training and/or discipline of maintenance personnel.

Given that the above factors have a bearing upon the reliability of equipment used in the Lifetime Costs of Subsea Production Systems, the project team considers it essential that this class of failures is taken into account in some form. Therefore, for this Lifetime Costs of Subsea Production System Study a model is used to describe both the "Early Life" failures by an "installation" unreliability, which is independent of the time taken to complete the operation, and the random/wear out failures of components using the time dependent exponential distribution (a constant failure rate over time). The probability of not experiencing failures related to installation or random failures during a period of time *t* is therefore estimated by the reliability distribution:

$$R(t) = \begin{cases} R(0) & , t = 0 \\ R(0) \cdot e^{-\lambda t} & , t > 0 \end{cases} \tag{7.21}$$

where *R(0)* is the "installation" reliability and $e^{-\lambda t}$ is the constant failure rate function.

The installation reliability is considered to be an important part of the overall system reliability and information has been assembled on the sealing reliability of system components based upon:

- Seal type.
- Installation method.
- Location within the system.

This information allows the various seal types to be ranked in order of likely "installation" failure probability. Absolute installation reliability values were then assigned to the individual components based upon "engineering judgement" and experience surveys supplied by the representatives from the sponsor companies.

7.1.8.4 Severity of Barrier Failures

The severity of a barrier failure depends on the size of the uncontrolled leak path in question. For the purpose of this study the following three severity categories have been adopted:

1. Limited.
2. Major.
3. Extreme.

For a specific *sealing barrier/component* this study has assumed for simplicity that the uncontrolled leak could either be “Limited” or “Extreme”. The severity of an uncontrolled leak on the *system level* is calculated according to the following rules:

Table 7.6: Rules to Determine Severity of Barrier Failure on System Level

Severity of Barrier Failure		
Barrier		Severity of Top Event
Primary	Secondary	
Limited	Limited	Limited
Extreme	Extreme	Extreme
Limited	Extreme	Major
Extreme	Limited	Major

Based on this the following equations were derived:

$$\begin{aligned}&P(\text{Extreme leak from comp. } i)\\&= P(\text{leak from comp.} i) \cdot P(\text{extreme leak} \mid \text{leak from comp.} i)\end{aligned}$$

$$\begin{aligned}&P(\text{Limited leak from comp. } i)\\&= P(\text{leak from comp.} i) \cdot P(\text{limited leak} \mid \text{leak from comp.} i)\\&= P(\text{leak from comp.} i) \cdot [1 - P(\text{extreme leak} \mid \text{leak from comp.} i)]\end{aligned} \tag{7.22}$$

The approach described above requires that for each component included in the FTA the fraction of extreme (limited) uncontrolled leaks must be estimated (ref. Section “Reliability Data and Assumptions”).

7.1.8.5 Dependence (Common Cause/Mode) Failures

In reliability generally and fault tree work in particular, there is a fundamental assumption which is, that the events considered are statistically independent unless stated otherwise. In practice, there are many types of situation where the events are not completely independent. This issue is normally referred to as “common mode” or “common cause” failures but is usually referred to as dependence.

Dependent failures take various forms. In most cases it requires that there is a common susceptibility in the component concerned. From work on dependent failure the following have been identified as causes of dependent failure:

1. A common utility (i.e., common supply of hydraulic fluid to the SCSSVs).
2. A common defect in manufacture.
3. A common defect in application.

or common exposure to:

1. A degrading factor (i.e., loop currents).
2. External influence (i.e., dropped object impacts).
3. A hazardous event (i.e., fire on the topsides).
4. Inappropriate operation (i.e., operation when casing pressure exceeds certain limits).
5. Inappropriate maintenance (i.e. failure to measure wear in the riser following rotating operations).

In this study of the Lifetime Costs of Subsea Production Systems the possibility of some dependent failure effects on the system was modeled. The riser systems (from mudline to surface) were identified as the sub-system that is most susceptible to dependent failure. From previous work for the area of Dry Tree Risers, Table 7.7 gives a list of some of the possible dependent failure influences upon the riser systems.

Table 7.7: Potential Common Mode Failures

External damage to the riser barriers	Milling damage Rotation damage Premature perforating gun detonation Fatigue failure of the risers Vessel impact damage Dropped object damage Overload of riser system due to tension system failure

To deal with this problem of dependent failure in this study, the Lifetime Costs of Subsea Production Systems study team has used a model normally referred to as the β-model. The fundamental basis of this model is that a failure of a component may be due to one of two possible causes:

1. Circumstances that concern only the component independent of the condition of the remaining components. (Failure rate due these causes is denoted by λ_I).
2. Occurrence of an event/state whereby *both* components fail at the same time. (Failure rate due these causes is denoted by λ_C).

Assuming that time to failure is exponentially distributed and independent of these failure causes, the total failure rate λ can be written as:

$$\lambda = \lambda_I + \lambda_C \tag{7.23}$$

The β-factor, the "common cause factor", is defined as:

$$\beta = \frac{\lambda_C}{\lambda_I + \lambda_C} \Leftrightarrow \lambda_C = \beta\lambda \tag{7.24}$$

The β-factor is related to the degree of protection against common cause failures. Normally the β-factor is estimated based on sound engineering judgement, as the data sources available do not provide sufficient information to derive confident estimates.

Historical observations of β-factors for simply redundant components indicates a range $0.003 < \beta < 0.3$ and most common usage is $\beta=0.1$. Historically, it has been observed (Flemming 1974) that the variations in the value of β for different components/systems were rather smaller than the variations in either the two quantities forming the β ratio. The value of β can be limited by a unity, so that the failure probability of a set of components is automatically assessed to be lower than the failure probability of a single component.

7.1.8.6 Modeling Dependency Between Steps in Intervention Mode

The probability of an uncontrolled leak to the environment during a certain intervention/workover procedure is based on the probabilities (P_i) of having an uncontrolled leak during each individual step (i). These probabilities are each conditional on surviving the previous stages, so the probability of an uncontrolled leak during an intervention comprising n steps is:

$$\begin{aligned} P &= P_1 + (1-P_1)P_2 + (1-P_1)(1-P_2)P_3 + \ldots\ldots + (1-P_1)(1-P_2)\ldots.(1-P_{n-1})P_n \\ &= 1-(1-P_1)(1-P_2)(1-P_3)\ldots\ldots\ldots\ldots.(1-P_{n-1})(1-P_n) \end{aligned} \tag{7.25}$$

The transition from a step to another is normally associated with a change in the barrier system. There will be extensive testing of the "new" barrier before the "old" barrier is demobilized. Therefore, for the purpose of this study it is assumed that the barrier system is "stochastically as good as new" at the beginning of each intervention step, which means that the probabilities, P_i, is just a function of the duration of each step i, not the age of the system or the duration of the previous steps. This is a simplification to represent the "real world" performance of a well completion system by a mathematical model. The successful completion of the previous steps does not necessarily imply that all completion components are functioning at the end of these steps (due to the redundancy in the barrier system) and that the completions system is as good as new at the beginning of each step.

7.1.8.7 Estimating the Uncontrolled Release Frequency for a Complete Riser System

If $N_{intervention,\ j}$ represent the number of uncontrolled leaks to the environment during intervention of type j (j = "Initial Installation – Frac Pack", "Initial Installation – Horizontal", "Workover – New Frac Pack", "Workover – Uphole Frac Pack", "Workover – Sidetrack, Frac Pack", "Workover – Sidetrack, Horizontal", "Repair Completions System leak", "Repair/Replace Subsea Tree", "Repair Coil Tubing Downhole"), and $N_{normal\ production}$ represent the number of uncontrolled leaks to the environment during normal production per well over a 10 year lifetime, the number of uncontrolled releases for a complete riser system has been estimated as:

$$N = m \cdot N_{normal\ production} + \sum_{All\ procedures\ j} n_j \cdot N_{intervention,j} \qquad (7.26)$$

where:

- n_j is the number of interventions of type *j* carried out during a 10 year lifetime for a system with *m* wells.
- *m is* the number of wells.

7.1.9 Reliability Data and Assumptions

This section describes in brief the reliability data used in this study and the key assumptions made regarding this data. Further reference is made to Section 6.

7.1.9.1 Introduction

The analysis of the Lifetime Costs of Subsea Production Systems requires the use of reliability (failure) data to allow the calculation of the "Top Event." Such data may be obtained from sources such as literature, data banks or from experience surveys. One important point to remember in this analysis is that it is wasteful to seek greater accuracy in the data than the problem warrants. Therefore, for the less critical components[4] in the Lifetime Costs of Subsea Production Systems study, coarse estimates for the input data may be appropriate. In the fault tree analysis some branches of the tree may be sensitive to the failure rates used whereas others may not be.

Some of the failure data is based upon expert judgements as this has been the only source of information available. A survey form was developed and completed by the participants. The survey was used to provide a series of reference points representing the participants' experience with similar types of equipment.

7.1.9.2 Types of Failure Data

The study has earlier discussed the applicability of the negative exponential failure distribution to the modeling of the system failures. In addition the concept of the "Bath Tub Curve" was also introduced. This study of the reliability of Lifetime Costs of Subsea Production Systems has tried to take account of two phases of the life of completion components namely "Installation" Failure and a "Constant" Failure Rate regime. The general effect of random failures was not considered appropriate over the field life of 10 years. Therefore, two types of failure information are required. These is an "installation" failure probability and a "constant" failure rate of the component.

[4] Known by experience

In terms of the Bath Tub Curve these two represent the “Early Life” failures and the “Random Failure” regimes respectively. It may be that the “constant” failure rate regime represents the wear out phenomena of various components. This fact is based on the assumption that when individual component failure rates are aggregated together it results in an exponential or “constant” failure rate for a system. For the true “wear out” to occur the following failure mechanisms are generally considered appropriate:

- Fatigue.
- Wear.
- Corrosion.
- Erosion.
- Creep.

Without detailed failure analysis of individual system components it is difficult to ascertain if any of these failure mechanisms are at work. It may be that some components in the system exhibit wear out failure characteristics. For the purposes of this analysis it has been assumed that if this is the case they will be covered by the “constant” failure rate regime adopted.

7.1.9.3 Useful Conversion Rules

To get a better understanding of the implication of the failure rates listed in Table 7.8 it could be useful to have the following in mind:

A. Conversion between failure rate (# failures per 10^6 hours) and Mean Time Between Failure (MTBF)

$$MTBF\ [years] = \frac{1}{(Failure\ rate)\ x\ (8760)} \tag{7.27}$$

The factor 8760 is the number of hours per year and serves as a conversion factor between *year* and *hour*. A failure rate of

- $114x10^{-6}$/hour is approximately the same as an MTBF of 1 year,
- $11x10^{-6}$/hour is approximately the same as an MTBF of 10 year, and
- $1x10^{-6}$/hour is approximately the same as an MTBF of 100 year.

B. Mean time to failure is the total observation period divided by the total number of failures within the period. For instance, if there has been 20 packers (or similar) in operation for, say, 10 years, 5 units for 20 years and 1 unit for 15 years, and there has been 3 failures related to these units, an estimate of the MTBF would be:

$$\frac{20x10 + 5x20 + 1x15}{3} = 105\ years \tag{7.28}$$

7.1.9.4 Recommended Failure Data

It is important to understand that reliability parameters are statistical averages. For example, it is highly unlikely that any particular component will fail at precisely the statistical average time to failure but the time to failure for all components will average to the average time to failure.

The Failure Mode Effects and Consequence Analysis determined a qualitative ranking of failure probabilities and identified the resource (rig or coiled tubing/wireline) needed to repair each failure mode. A more quantitative estimate of component reliabilities was then developed from statistical databases, engineering judgement (EJ) and ranking methods. WellMaster, OREDA, WOAD, E&P Forum, the Dry Tree Tieback Alternative Study (DTTAS) Joint Industry Study and other sources were used to develop the data set of default values that are listed below. These default values provide a starting point for analyses. They should be modified as necessary to improve the correlation between the model predictions and reality.

The default data for leak failures is intended to include only large leaks that require a workover before production is reestablished. Small leaks that might cause annulus pressure are assumed to be of negligible consequences because production may continue if the annulus pressure is periodically bled off to comply with MMS regulations. The probability of large leaks is typically assumed to be about an order of magnitude less than the probability of small leaks.

Refer to Section 4.3 for a more detailed explanation of reliability data.

Tubing Joint (per joint)

Failure Mode: Leak

Installation Failure Probability = **2.0 E–6 per joint**.
Fraction of Extreme Leaks = **0.1**
Data Source: Dry Tree Tieback Alternatives Study (DTTAS)
Comments: Multiply by the number of joints for tubing string consisting of multiple joints.

MTTF (Constant Failure Rate)= **17,000 years per joint.**
Fraction of Extreme Leaks = **0.1**
Data Source: WellMaster Database
Comments: Divide by the number of joints for tubing string consisting of multiple joints.

Surface Controlled Subsurface Valve (SCSSV)

Failure Mode: Failure to Close

Installation Failure Probability = **4.0 E -3**
Fraction of Extreme Leaks = **0.2**
Data Source DTTAS
Comments:

Failure Mode: Leak in closed position.

Installation Failure Probability = **4.0 E –3**
Fraction of Extreme Leaks = **0.2**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **89 years**.
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

Failure Mode: External leak

Installation Failure Probability = **1.0 E –2**
Fraction of Extreme Leaks = **0.7**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **2,200 years**.
Fraction of Extreme Leaks = **0.7**
Data Source: DTTAS
Comments:

Side Pocket Mandrel

Failure Mode: Large leak or parted or collapse.

Installation Failure Probability = **1.0 E –2**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **250 years**.
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

Instrument Port

Failure Mode: Large leak or parted.

Installation Failure Probability = **2.0 E –3**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **456 years**.
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments:

Packer

Failure Mode: Large leak.

Installation Failure Probability = **2.0 E –2**
Fraction of Extreme Leaks = **0.2**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **300 years**.
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

Chemical Injection Valve

Failure Mode: Plugged or large leak.

Installation Failure Probability = **5.0 E –2**
Fraction of Extreme Leaks = **0.5**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **100 years**.
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments:

Pipeline

Failure Mode: External leak

Installation Failure Probability = **1.0 E –3**
Fraction of Extreme Leaks = **0**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **700 years**.
Fraction of Extreme Leaks = **0**
Data Source: ARF (Confidential DNV document)
Comments: Wear-out rate is based on a 20 km pipeline at a water depth of 5000 feet.

PLEM Valves

Failure Mode: Fail to close

Installation Failure Probability = **1.2 E-2**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

Probability of failure on demand = **1.0 E-1**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

Failure Mode: External leak

Installation Failure Probability = **1.2 E-2**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

MTTF (Constant Failure Rate) = **60 years.**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

Manifold Isolation Valves

Failure Mode: External leak

Installation Failure Probability = **1.2 E-2**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

MTTF (Constant Failure Rate)= **60 years.**
Fraction of Extreme Leaks = **0**
Data Source: Confidential DNV document
Comments:

Subsea Isolation / Master Valves

Failure Mode: Large external leak

Installation Failure Probability = **1.0 E-3**
Fraction of Extreme Leaks = **0.05**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **1000 years**
Fraction of Extreme Leaks = **0.05**
Data Source: EJ
Comments:

Failure Mode: Failure to close on demand

Installation Failure Probability = **1.0 E-3**
Fraction of Extreme Leaks = **0.2**
Data Source: EJ
Comments:

Failure on demand probability = **1.9 E-3 years**
Fraction of Extreme Leaks = **0.2**
Data Source: EJ
Comments:

X-O Production / Annulus Stab Seals

Failure Mode: Large leak

Installation Failure Probability = **4.0 E-2**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as the tubing riser / tubing spool production stab seals for the Dry Tree Tieback Alternative Study.

MTTF (Constant Failure Rate)= **242 years**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as the tubing riser / tubing spool production stab seals for the Dry Tree Tieback Alternative Study.

Subsea BOP (multiple rams and annulars)

Failure Mode: Fail to close

Installation Failure Probability = **6.0 E-3**
Fraction of Extreme Leaks = **0.2**
Data Source:
Comments:

Fail to Operate on Demand Probability = **1.0 E-3**
Fraction of Extreme Leaks = **0.05**
Data Source:
Comments:

Gaskets

Failure Mode: Large leak

Installation Failure Probability = **1.0 E-6**
Fraction of Extreme Leaks = **0.01**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **1400 years**
Fraction of Extreme Leaks = **0.01**
Data Source: DTTAS
Comments:

Tree Test Valves

Failure Mode: Leak in the closed position

Installation Failure Probability = **6.0 E-4**
Fraction of Extreme Leaks = **0.01**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as the ROV annulus shut-off valve for the Dry Tree Tieback Alternative Study.

MTTF (Constant Failure Rate)= **56 years**
Fraction of Extreme Leaks = **0.01**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as the ROV annulus shut-off valve for the Dry Tree Tieback Alternative Study.

Subsea Tubing Hanger

Failure Mode: Large body leak

Installation Failure Probability = **1.0 E-4**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **127 years**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments:

Isolation Stab Seals

Failure Mode: Large leak

Installation Failure Probability = **1.5 E-4**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as the tubing spool / WH housing seal used for Tubing Risers in the Dry Tree Tieback Alternative Study.

MTTF (Constant Failure Rate)= **400 years**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as the tubing spool / WH housing seal used for Tubing Risers in the Dry Tree Tieback Alternative Study.

Casing Hanger Packoff

Failure Mode: Large leak

Installation Failure Probability = **1.5 E-4**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as the casing hanger lockdown sleeve seal used for Tubing Risers in the Dry Tree Tieback Alternative Study.

MTTF (Constant Failure Rate)= **400 years**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as the casing hanger lockdown sleeve seal used for Tubing Risers in the Dry Tree Tieback Alternative Study.

Casing Joints (per joint)

Failure Mode: Large leak through joint

Installation Failure Probability = **6.0 E-6**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Multiply by the number of joints for casing string consisting of multiple joints.

MTTF (Constant Failure Rate)= **24,420 years**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Divide by the number of joints for casing string consisting of multiple joints.

Tubing Hanger Production Bore Plugs

Failure Mode: Large leak

Installation Failure Probability = **1.0 E-2**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **100 years**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

Tubing Hanger Annulus Bore Plugs

Failure Mode: Large leak

Installation Failure Probability = **5.0 E-2**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **4 years**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

Kill Fluid

Failure Mode: Loss of circulation

Installation Failure Probability = **1.0 E-1**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **4 years**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

Failure Mode: Dead Head (Blockhead)

Installation Failure Probability = **5.0 E-1**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **4 years**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

High Pressure Caps

Failure Mode: Large leak

Installation Failure Probability = **1.5 E-4**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as a casing hanger packoff leak

MTTF (Constant Failure Rate)= **400 years**
Fraction of Extreme Leaks = **0.05**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as a casing hanger packoff leak

Tubing Hanger Plugs (Horizontal Tree)

Failure Mode: Large leak

Installation Failure Probability = **1.0 E-2**
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as a tubing production bore leak

MTTF (Constant Failure Rate)= **100 years**
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as a tubing production bore leak

Isolation Sleeves

Failure Mode: Large leak

Installation Failure Probability = **1.0 E-2**
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as a tubing production bore leak

MTTF (Constant Failure Rate)= **100 years**
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as a tubing production bore leak

High Pressure Wear Bushings

Failure Mode: Large leak

Installation Failure Probability = **2.0 E-1**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments: Failure probability assumed to be the same as a wireline installed packer plug

MTTF (Constant Failure Rate) = **1 year**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments: Failure rate assumed to be the same as a wireline installed packer plug

Packer Plug (wireline installed)

Failure Mode: Large leak

Installation Failure Probability = **2.0 E-1**
Fraction of Extreme Leaks = **0.5**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **1 year**
Fraction of Extreme Leaks = **0.2**
Data Source: DTTAS
Comments:

Cement Retainer

Failure Mode: Large leak

Installation Failure Probability = **2.0 E-4**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

MTTF (Constant Failure Rate)= **1000 years**
Fraction of Extreme Leaks = **0.1**
Data Source: DTTAS
Comments:

Completion Riser BOP

Failure Mode: Fail to close on demand

Installation Failure Probability = **3.0 E-2**
Fraction of Extreme Leaks = **0.2**
Data Source: EJ
Comments:

Failure on demand probability = **0.01**
Fraction of Extreme Leaks = **0.05**
Data Source: EJ
Comments:

Tree (surface and subsea)

Failure Mode: Large body leak

Installation Failure Probability = **1.0 E-5**
Fraction of Extreme Leaks = **0.05**
Data Source: EJ
Comments:

MTTF (Constant Failure Rate)= **2400 years**
Fraction of Extreme Leaks = **0.05**
Data Source: EJ
Comments:

7.1.9.5 Failure Rate Data Summary

Table 7.8: Conventional and Horizontal Tree Systems

Completion Component Item	Installation Failures		Random Failures – Revealed		Random Failures – Unrevealed	
	Probability	Extreme Fraction	MTBF (years)	Extreme Fraction	Probability of Failure on Demand	Extreme Fraction
Subsea Tree / Manifold						
Pipeline EXL	1.0×10^{-3}	0	700	0		
PLEM valve FTC	1.2×10^{-2}	0	1000000	0	0.1	0
PLEM valve EXL	1.2×10^{-2}	0	60	0		
Manifold isolation valve EXL	1.2×10^{-2}	0	60	0		
PIV EXT	1.0×10^{-3}	0.05	1000	0.05		
PIV FTC	1.0×10^{-3}	0.2	1000000	0.2	0.0019	0.2
Tree EXL	1.0×10^{-5}	0.05	2400	0.05		
Production wing valve EXL	1.0×10^{-3}	0.05	1000	0.05		
Annulus vent valve EXL	1.0×10^{-3}	0.05	1000	0.05		
Subsea Tree – Up (Production)						
UMV EXL	1.0×10^{-3}	0.05	1000	0.05		
LMV FTC	1.0×10^{-3}	0.05	1000000	0.2	0.0019	0.2
LMV EXL	1.0×10^{-3}	0.05	1000	0.05		
X-O prod stab seals	2.0×10^{-6}	0.2	242	0.05		
High pressure cap	1.5×10^{-4}	0.05	400	0.05		
Tubing hanger plug	1.0×10^{-2}	0.5	100	0.2		
Isolation sleeve (to production outlet)	1.0×10^{-2}	0.5	100	0.2		
High pressure wear bushing	2.0×10^{-1}	0.2	1	0.2		
Subsea Tree – Up (Annulus)						
AMV EXL	1.0×10^{-3}	0.05	1000	0.05		
X-O ann stab seals	4.0×10^{-2}	0.2	242	0.05		
Completion Riser - THRT up (Production)						
SPSV EXL	6.0×10^{-3}	0.05	1000	0.5		
SPMV EXL	6.0×10^{-3}	0.05	1000	0.5		
UBOP FTC	3.0×10^{-2}	0.2	1000000	0.1	0.01	0.05
LBOP FTC	3.0×10^{-2}	0.2	1000000	0.1	0.01	0.05
Completion Riser - THRT up (Annulus)						
SASV FTC	1.0×10^{-4}	0.05	1000000	0.05		
SAMV FTC	1.0×10^{-4}	0.1	1000000	0.05		
AIV FTC ABOP FTC	1.0×10^{-3} 3.0×10^{-2}	0.2 0.2	1000000 1000000	0.2 0.1	0.0019 0.01	0.05 0.05
Test tree valves FTC	2.0×10^{-3}	0.2	1000000	0.2	0.0019	0.05
Surface tree EXL	1.0×10^{-5}	0.05	2400	0.05		
Marine Riser						
Subsea BOP FTC (multiple rams and annular)	6.0×10^{-3}	0.2	1000000	0.2	0.001	0.05
Casing – SS Wellhead Connector down						
Wellhead conn. gasket leak	1.0×10^{-6}	0.01	1400	0.05		
Tree connector test valve LCP	6.0×10^{-4}	0.01	56	0.05		
Tubing hanger annulus bore plug leak	5.0×10^{-2}	0.2	4	0.2		
TH body seal to THS	1.0×10^{-4}	0.05	127	0.05		

Completion Component Item	Installation Failures		Random Failures – Revealed		Random Failures – Unrevealed	
	Probability	Extreme Fraction	MTBF (years)	Extreme Fraction	Probability of Failure on Demand	Extreme Fraction
TH spool gasket leak	1.0×10^{-6}	0.05	1400	0.05		
Cavity testport isolation valve LCP	6.0×10^{-4}	0.05	56	0.05		
Isolation stab leak	1.5×10^{-4}	0.05	400	0.05		
Casing hanger pack-off leak	1.5×10^{-4}	0.05	400	0.05		
Packer to casing seal leak	1.0×10^{-2}	0.85	330	0.2		
13 3/8" casing hgr seal	1.5×10^{-4}	0.05	400	0.05		
Tubing Hanger – Packer up to stab seals						
Tubing hanger production bore plug leak	1.0×10^{-2}	0.1	100	0.1		
Chemical injection valve/or chem. line leak	5.0×10^{-2}	0.5	100	0.05		
SCSSV LCP	4.0×10^{-3}	0.2	89.4	0.2		
SCSSV EXL (e.g., control line leak)	1.0×10^{-2}	0.7	2200	0.05		
SCSSV FTC	4.0×10^{-3}	0.2	1000000	0.2		
Side pocket mandrel	1.0×10^{-2}	0.1	250	0.1		
Instrument port	2.0×10^{-3}	0.05	456	0.05		
Tubing in Packer - Seal assembly	2.0×10^{-2}	0.2	300	0.1		
Packer plug (wireline installed plug)	2.0×10^{-1}	0.5	1	0.2		
Cement Retainer	2.0×10^{-4}	0.1	1000	0.1		
Operational Barriers						
Kill Fluid (Circulation)	1.0×10^{-1}	0.1	4	0.1		
Kill Fluid (Dead Head)	5.0×10^{-1}	0.1	4	0.1		

7.1.9.6 Other Data

The data given in Table 7.9 was used to calculate the reliability for the various risers, casing and tubing strings.

Table 7.9: Joint Density Figures for Riser, Casing and Tubing

Riser System	Feet/Joint
Tubing	40
Casing	45
Drilling riser	63
Completion riser	40

7.2 Leak Logic and Consequence Cost

7.2.1 Leak Logic Introduction

The purpose of this section is to provide an explanation of the proposed quantification of leaks from the "primary and secondary" containment systems.

In addition, the section provides a proposal for the estimation of the risks associated with failure of the secondary containment system and possible release to the environment. It is important that the consequences of component and system failure be established so as to enable a risk cost to be assigned to the various outcomes of system failure.

7.2.2 Leak Logic Methodology

7.2.2.1 Primary Containment

To address the problem of annulus pressure build up in the three different systems the various failures of the system components are grouped into three different categories using a logic tree to aid the process. The three categories are as follows:

- ***Nuisance:*** Pressure builds up in the inner annulus, which can be bleed off and does not re-appear. An example would be annulus pressure caused by thermal expansion.
- ***Limited:*** Pressure build up in the inner annulus, but the seals or the barrier where the leak has occurred is providing a certain amount of restriction. The pressure may, or may not, exceed the 20% of the internal yield pressure of the casing string and may, or may not, be bleed off within the prescribed time required by the MMS to permit the well to be produced.
- ***Extreme:*** From the conditions in the well it is evident that a total loss of a primary barrier or primary seal failure has occurred. Therefore the well will have to be shut in and an intervention is required to put the well back on production.

7.2.2.2 Secondary Containment

The “secondary containment” system is defined as the entire outer pressure-retaining envelope, including any tertiary barrier or seal elements. If annulus pressure created by a “primary containment” system component failure is contained by this “secondary containment” system, an intervention operation can be undertaken to allow remedial work to be performed. Alternatively if the “secondary containment” system component fails without any failure in the “primary containment” an intervention operation will also be required. If prior to or during the intervention a second failure occurs in either of the other containment systems, then it is likely that a release to the environment will occur. As with the “primary containment” failure there is a requirement to classify the magnitude of the failure of the “secondary containment” system. The size of the failure has again been classed as either “Limited” or “Extreme”. The two categories are as follows:

- ***Limited:*** The secondary containment system leaks at a slow rate to moderate rate when pressurized.
- ***Extreme*** : Alternatively the failure of the “secondary containment” is mechanical or structural in nature. Secondary pressure containment has been totally lost. An example of such a failure would be a fatigue crack in the riser, or tubing plug that fails to latch into place.

7.2.2.3 Consequence Categories

Given the above, definitions are used to establish the consequence category ratings where both the “Primary and Secondary barriers have failed”.

These consequence categories are then used to establish a series of risk costs. The risk costs define the consequence of failure, which results in a “release of hydrocarbons to the environment”. The consequence definitions are outlined below:

- ***Limited:*** Small hydrocarbon spillage or release at a limited rate. The release at this limited rate may continue for some days. Local spill response is required to clean up. Some form of intervention is required to remediate the situation. In terms of flow rate the limited category is defined as 6.6% of the maximum well’s flow potential of 15 MBOPD i.e. 1,000 barrels per day.

  No threat to life.

  No immediate threat to the integrity of the installation.

- ***Major:*** Significant liquid Hydrocarbon spill or large release of gaseous hydrocarbon. Major spill response is required to clean up. The pressure retaining and controlling capability of the system is ineffective for days. In terms of flow rate the major category is defined as between 6.6% and 33% of the maximum well’s flow potential of 15 MBOPD i.e. 1,000 to 5,000 barrels per day.

  Serious injury and possible threat to life.

Major damage to the facility.

Could be classed as a limited scale blowout.

- ***Extreme:*** Large scale liquid hydrocarbon spill or massive gaseous release. Full-scale response required to control the incident and clean up. In terms of flow rate the extreme category is defined as a flow between 33% and 100% of the maximum well's flow potential of 15 MBOPD i.e. 5,000 to 15,000 barrels per day.

  Loss of life.

  Loss of the facility.

  Could be classed as a full-scale blowout, possibly from multiple wells caused by escalation.

7.2.3 Leak Logic Consequence Categories

The above information has been used to provide a banding of the consequence categories to permit the estimation of the level of risk from potential failures in the components of the systems. For these consequence categories a set of risk cost figures is developed in the next section titled "Consequence Costs".

Table 7.10: Consequence Category Rating

Primary Containment Failure	Secondary Containment Failure	Consequence Category Rating
Extreme failure	Extreme failure	Extreme consequences
Extreme failure	Limited failure	Major consequences
Limited failure	Extreme failure	Major consequences
Limited failure	Limited failure	Limited consequences

7.2.3.1 Component Leak Rates

The design maximum flow rate from one of the wells in this study is 15 MBOPD. For the individual components in the system the JIP Project team with the assistance of available data and participants survey information has identified a size of leak which would provide a "Limited" and "Extreme" leak from the system. The relative proportions of these sizes of leak were determined using available data as outlined above and "Engineering Judgement". No major engineering exercise was undertaken to determine actual equivalent hole sizes and then calculate an equivalent leak rate at the pressure. It may be that the initial leak rate would be small but it would quickly increase.

7.2.4 Consequence Costs

7.2.4.1 Introduction to Consequence Costs

The following outlines the potential costs of a catastrophic failure of weell control barriers in a high rate offshore well system. These cost estimates provide a basis for the various risk cost consequences.

The cost an offshore well control system failure is made up of various elements. In addition, there is likely to be differences between different areas of the world in respect to pollution response. The loss of a new facility soon after it has been installed will obviously be much greater than one where the field life is nearly exhausted. Finally, the historical analysis of blowout costs does not take account of the time value of money. Obviously the $10MM cost in 1980 could be substantially higher in 1998. These historical blowout costs are used as a basis for calibrating a prediction model of the costs based on cost for clean up and outrage.

7.2.4.2 Costs of Offshore Failures

The following is a table of "well control" related costs obtained from References 1 and 2. The costs, where applicable, have been broken down into different categories that make up the overall cost. The project team has broken these costs down by three different areas namely North Sea/Europe, Gulf of Mexico, and other parts of the world.

Table 7.11: Well Loss Costs (North Sea)

Location	Type of Incident	Date	Cost	Type of Damage
1 North Sea	Explosion and fire on Piper Alpha (Well costs only)	7/88	$4.0MM $34.0MM $87.0MM	Pollution costs Cost of Clean up Re-drill costs
2 North Sea	Surface Blowout Ocean Odyssey	9/88	$16.1MM $13.9MM	Cost of Clean up Re-drill costs
3 North Sea	Underground Blowout	1/89	$215.0MM	
4 France	Underground Blowout on producing well	2/90	$9.0MM $12.0MM	Re-drill costs Cost of Clean up
5 North Sea	Casing failure during development drilling	8/91	$8.2MM	Operators extra expenditure
6 North Sea	Blowout of high pressure well during exploration drilling	9/91	$12.25MM	Operators extra expenditure
7 North Sea	Underground Blowout during exploration drilling	4/92	$17.0MM	Operators extra expenditure
8 North Sea	Well control incident	11/92	$10.97MM	Operators Extra expenditure
9 North Sea	Re-drill following blowout	5/93	$8.25MM	Re-drill costs
Total # Events		9	$447.7MM	Average cost $50.0MM
Total Cost	Excluding Event No 3	8	$232.7MM	Average Cost $29.0MM
Range of costs	Excluding Event No 3			$8.2MM to $125MM

Table 7.12: Well Loss Costs (Gulf Of Mexico)

Location	Type of Incident	Date	Cost	Type of Damage
1 Gulf of Mexico	Blowout caused by casing rupture	10/88	$12.4MM	
2 Gulf of Mexico	Underground blowout	7/90	$1.5MM	Cost of Clean up
3 Gulf of Mexico	Blowout	2/92	$6.4MM	Operators Extra costs
4 Gulf of Mexico	Blowout during drilling operations	10/92	$10.0MM	
5 Gulf of Mexico	Blowout	2/93	$7.0MM	
6 Gulf of Mexico	Blowout	1/94	$7.5MM	Operators extra expenditure
7 Gulf of Mexico	Blowout	6/94	$10.0MM	
8 Gulf of Mexico	Surface blowout of producing well 11 wells lost	11/95	$20.0MM	Cost of wells and physical damage costs
9 Gulf of Mexico	Underground blowout	4/96	$8.3MM	
Total Number of Events		9	$83.1MM	Average cost $9.2MM
Range of costs				$1.5MM to $20MM

When comparing the cost of a blowout in the North Sea to that of the Gulf of Mexico it can be clearly seen that in the Gulf of Mexico the cost is a great deal lower than the cost in the North Sea. It is believed at this time that the actual costs of an extreme failure from a deepwater well may not be truly reflected in the above figures for the Gulf of Mexico.

Table 7.13: Well Loss Costs (Other Areas)

Location	Type of Incident	Date	Cost	Type of Damage
Africa	Platform blowout. Severe damage and relief well drilled to extinguish fire	12/89	$21.0MM	Cost of Clean up
Middle East	Platform hit by vessel damage to wells	12/89	$14.0MM $50.0MM $0.5MM	Cost of Clean up Re-drill costs Pollution costs
Middle East	Underground blowout when drilling	11/90	$40.0MM	
Trinidad	Well intersected causing blowout during development drilling	4/91	$9.0MM	Operators extra expenditure
Mexico	Explosion and blowout	8/91	$16.6MM	Operators extra expenditure
Taiwan	Underground blowout during drilling	5/92	$18.9MM	Operators extra expenditure
India	Blowout during drilling	9/92	$5.5	Operators Extra expenditure
Vietnam	Surface gas blowout followed by underground flow	2/93	$6.0MM $54.0MM	Re-drill costs Cost of the well
Vietnam	Underground blowout	8/93	$8.65MM	Operators extra expenditure
Vietnam	Underground blowout	1/94	$14.0MM	Operators extra expenditure
Vietnam	Underground blowout during drilling	10/95	$10.0MM	
Philippines	Blowout of exploration well	8/95	$6.0MM	Cost of the well
Total Number of Events		12	$274.2MM	Average cost $22.8MM
Range of costs				$5.5MM to $64.5MM

7.2.5 Overall Results of Cost Data Survey

The data from the North Sea and Europe has identified 9 individual incidents with an average cost of $50.0MM. When the largest event is removed from the figures this gives an average cost of $29.0MM, with a range costs of $8.2MM and $125MM. For the Gulf of Mexico the average cost is $9.2MM which is much lower than the North Sea and a range of $1.5MM to $20.0MM. For the rest of world the average costs are somewhere between the Gulf of Mexico and the North Sea figure and the range is between $5.5MM to $64.5MM.

Table 7.14 is taken from reference 3 and is used as a check on the above figures. It should be noted that the two data sets are not mutually exclusive some events appear in both sets.

Table 7.14: Blowout Costs for Major Incidents Since 1980

Location	Type of Incident	Date	Cost	Type of Damage
Trinidad	Blowout	1980	$15.0MM	
Matagorda Island 622	Blowout	1980	$5.0MM	
Gabon	Blowout	1981	$15.0MM	
Texas Key 1-11 well	Blowout	1982	$52.0MM	
Lodgepole	Blowout	1982	$52.0MM	
Indonesia Arun	Blowout	1984	$78.0MM	
Louisiana St. Romaine	Blowout	1985	$14.0MM	
Nova Scotia W.Venture	Blowout	1985	$124.0MM	
Texas Marshall well	Blowout	1985	$50.0MM	
Indonesia Belepai platform	Blowout	1985	$56.0MM	
S.China Sea Weishou	Blowout	1986	$13.0MM	
Manchuria PRC oil	Blowout	1986	$22.0MM	
Congo Tchibilia well	Blowout	1986	$45.0MM	
Mexico	Yum 2 well	1987	$46.0MM	
India Bay of Bengal	Underground blowout	1987	$25.0MM	
Texas Brazile 1 well	Blowout	1987	$3.0MM	
Brazil Enchove	Platform loss caused by blowout	1988	$530.0MM	Platform and re-drill costs
North Sea UK	Platform loss (Total costs)	1988	$1360MM	Piper Alpha see above
North Sea Well	Blowout	1989	$284.0MM	Norwegian well 2/4-14
North Sea Well	Blowout	1991	$5.0MM	Norwegian well 2/4-16
Kuwait	Large scale multiple wells	1991	$5400MM	Military destruction of Kuwait oil fields
Total Cost		21	$8194MM	Average cost $390.0MM
Total Cost	Excluding events >$200MM	17	$620MM	Average cost $36.5MM
	Range excluding >$200MM			$3.0MM to $124.0MM

Table 7.14 covers a whole range of blowouts with some of the extreme events included. When the total cost of the blowout is included with 21 events the average cost of a blowout is $390MM. If the three largest incidents (>$250MM) are averaged out (excluding Kuwait) the average cost is $725.0MM. If the Kuwait figures are included the average is $1900MM.

7.2.5.1 Discussion

From the above table it is evident that large-scale blowout costs can vary dramatically. In the table there are some extremely large incidents which would equate to the extreme event in the cost consequence tables. Other blowout incidents though are not as large scale as these dramatic events and would in the risk analysis be classed as major events.

In an article by Mr. L W Abel of Wild Well Control Inc. (Ref 3) there is a qualitative description of the classification of blowouts by type and degree of severity. These descriptions are outlined below:

- **Class I**

  A minor event in which the well may only be leaking and is not on fire.

  Minor pollution might occur.

  Hazards are minimal providing the conditions do not worsen or other failures do not affect the situation.

- **Class II**

  A small to medium event in which the flow rates range about 20 to 50 MMscfd of gas and 20,000 to 50,000 barrels/day of liquid.

  The flow may exit either subsurface or above the surface of the seabed.

  The well is not on fire , and access to the wellhead is possible.

  Pollution may occur but is not major, and the fluids are not considered toxic.

- **Class III**

  A small to medium event in which the flow rates range about 20 to 50 MMscfd of gas and 20,000 to 50,000 barrels/day of liquid.

  The flow may exit either subsurface or above the surface of the seabed.

  The well may or may not be on fire, and access to the wellhead is not difficult.

  Pollution may occur, and the fluids can be hazardous.

- **Class IV**

  A medium event in which the flow rates range about 20 to 50 MMscfd of gas and 20,000 to 50,000 barrels/day of liquid.

  The flow may exit either subsurface or above the surface of the seabed.

  The well may or may not be on fire, and access to the wellhead is difficult but possible.

  Large amounts of pollution may occur, and the fluids can be hazardous.

- **Class V**

  A major event in which the flow rates range in excess of 100 MMscfd of gas and 50,000 barrels/day of liquid.

  The flow may exit either subsurface or above the surface of the seabed.

  The well may or may not be on fire. Usually access to the wellhead is difficult or impossible, as in deep water or severely damaged platform.

  Large amounts of pollution occur, and the fluids can be hazardous.

Taking the above classifications and our proposed risk cost categories it would be applicable to categorize the “Limited”, “Major”, and “Extreme” categories into the above classes. The “Limited” category would likely be Class I, the Major category would be Class II, and the Extreme would be Class III, IV and V.

7.2.5.2 Gulf of Mexico Oil Spill Statistics

The Minerals and Management Service of the Department of the Interior has produced statistics for oil spills in the Gulf of Mexico for the period 1970 to 1990 (ref 4). This information is based upon reportable spills for the Gulf of Mexico and includes blowouts in the analysis. The data in the report is reported in two stages:

1. Large spills of greater than 1000 bbls from platforms in the Gulf of Mexico.
2. Blowout spills in the Gulf of Mexico.

For this analysis the data from the MMS is repeated in the following tables.

Table 7.15: Large Spills (>1000 bbls) from Platforms Gulf of Mexico (1970 to 1990)

Date	Spill Size (bbls)	Material
12/1/70	53,000	Oil
10/2/70	30,000	Oil
4/17/74	19,833	Oil
7/2/88	15,576	Oil
1/24/90	14,423	Condensate
1/9/70	9,935	Oil
1/26/73	7,000	Oil
12/11/81	5,100	Oil
5/12/73	5,000	Oil
5/6/90	4,569	Oil
12/18/76	4,000	Oil
9/11/74	3,500	Oil
11/24/79	1,500	Diesel
11/14/80	1,456	Oil

Table 7.16: Summary of Large Spills (>1000 bbls) from Platforms Gulf of Mexico

Material Spilt	Oil	Diesel	Condensate
Number of Spills	12	1	1
Amount Spilt (bbl)	158,969	1,500	14,423
Average	13,247	1,500	14,423

For blowouts the following statistics were identified in Ref 4.

Table 7.17: Blowout Spill in Gulf of Mexico (1970 – 1990)

Date	Spill Size (bbls)	Material
1/12/70	53,000	Oil
2/10/70	30,000	Oil
10/16/71	450	Oil
12/22/74	200	Oil
9/7/74	75	Oil
11/28/81	64	Oil
3/20/87	60	Condensate
2/23/85	40	Oil
5/30/90	12	Oil/mud
9/9/90	8	Condensate

Table 7.18: Summary of Blowout Spills for the Gulf of Mexico

Material Spilt	Oil	Condensate	Total
Number of Spills	8	2	10
Amount Spilled (bbl)	83,841	68	83,909
Average	10,480	34	N/A

Given the above information the average spill from a fixed installation is around 13,247 bbls of oil. For blowouts the average size of an oil spill is 10,480 in the Gulf of Mexico from the recorded blowout statistics. From this information the JIP project team suggests that a "minor" blowout be characterized by a figure of around 10,000 bbls of liquid.

7.2.5.3 Alternative Approach

To estimate if the cost figures outlined above are realistic for analysis of cost consequences, the JIP project team has taken a second approach to the problem of blowout costs. The proposed approach is to calculate the likely cost of clean up/spill response costs for a typical deepwater well blowout. The basis of this approach is to calculate a clean up cost figure based upon an average barrel spill. In addition there is a cost of "Public Outrage" to be added to these clean up/spill costs to account for fines, loss of public image etc.

7.2.5.4 Spill Costs (Response and Cleanup)

The following is some background data on the proposed costs of a clean up that DNV has used in previous studies.

1. DNV internal database estimates a cost of $1,000 per barrel spilled.
2. These data indicate that costs are much greater when coastal damage is involved. The larger the spill, the smaller the cost per barrel because:
    - The more oil is released, the easier it is to recover large amounts of it in a single pool of oil.
    - More oil release means that the release has taken place over a longer period of time. Thus the more volatile components of the oil may have evaporated, and the remaining heavier components have had more time to be eliminated through dispersion or biological action.
    - There is a minimum cost associated with any oil spill mitigation effort, regardless of duration. This cost, prorated, would be less on a per barrel basis for a prolonged event.

Contrary to the logic above, one can also suppose that a larger release from a deepwater Spar of TLP might involve larger per barrel costs. Given the distance that such facilities are likely to be from the shore, it is likely that a small leak will not have any shoreline (high cost) impact, whereas a major release might.

The confidential report provides the following costs (1992) for offshore events:

Table 7.19: Blowout Cost Figures

Place	Total Spill (bbls)	1992 Cost ($)	$/bbl
Santa Barbara	10,000	22 MM	2200
GoM	5,000	66 MM	13200
Ekofisk	21,000	14 MM	667
Nigeria	45,000	5 MM	110

The report concludes that a "conservative" value of $1000/bbl should be used in all cases. At first glance, this seems conservative only for larger spills in remote waters.

Therefore for the analysis of blowouts the JIP project team suggests the following values be used:

- $2,000/barrel for spills up to 10,000 barrels,
- $1,500/barrel for spillage from 10,000 up to 50,000 barrels and
- $1,000/barrel for spillage over 50,000 barrels.

For a spill of 200,000 barrels this gives a figure of $230MM. This compares favorably with a value from one source of $284MM as the largest well control (not including loss of platform and redrilling) in the events listed in Tables 8.1, 8.2, and 8.3.

7.2.5.5 Spill Costs (Outrage Costs)

The confidential report also indicates, outrage costs may include the following: (1) fines, (2) lost licenses/acreage rights, (3) reduced market share due to lost reputation, (4) suspension/cancellation of similar operations, (5) increased regulation/legislation of operations.

Outrage costs are hard to predict, and will vary among the different factors above depending on the size of the release - for example, a minor spill will probably have no effect on (3). The confidential report assumes a cost of zero to $300MM for an offshore spill of 200,000 barrels. Significant fines (1) may be assessed at low levels of spillage, and items (5), (2) and (4) may be invoked at progressively larger spill sizes. In general, we will assume a slightly progressive outrage cost, depending on spill size.

Therefore for the analysis of blowouts the JIP project team suggests the following values be used:

- $1000/barrel for spills up to 50,000 barrels, and
- $1500/barrel for amounts spilled over 50,000 barrels.

For this analysis where an event outcome could result in a potential spill the spill estimate has been a minimum of 10,000 barrels with the associated costs of $1500/barrel for clean up and $1000/barrel for outrage, which gives a value of $25.0MM.

7.2.5.6 Comparison

The above information was then assembled into a spreadsheet to calculate the overall costs based upon the following figures:

- Well flow rates of between 500 bbls per day to 60,000 bbls per day.
- Days to contain the blowout of between 5 and 175 days.

Taking this information this gives a range of blowout costs of between **$6.25MM** for 500 bbls per day for 5 days to **$7500MM** for 30,000 bbls per day for 100 days and **$26300MM** for 60,000 bbls per day for 175 days. Using this range of information the JIP project team calculated the relative cost of various incidents to compare with historical evidence.

Table 7.20: Proposed Blowout Cost Figures

Size of Blowout	Barrels per Day	Number of Days	Cost $MM	Average Blowout Cost $MM	Range for Average $MM
Limited	1000	10	$25.0	$29.0 Europe	$8.2 to $125
				$9.2 GoM	$1.5 to $20.0
				$22.8 Worldwide	$5.5 to $64.5
Major	5,000	30	$375	$390 Worldwide	
Extreme	15,000	60	$2,250	$725 excl Kuwait	
				$1900 incl. Kuwait	

The well flow rates in barrels per day represent 6.6% of the maximum well flow rate for a "Limited" case, 33% for the "Major" case and 100% of the maximum well flow rate for the "Extreme case.

Given the figures in the above table the JIP project team would recommend that the values for the spill and clean up costs outlined in the above table be used in the analysis of risk costs for the study.

7.2.6 Installation Damage Costs

In addition to the spill and clean up costs and outrage costs there will be additional costs for any damage to the facility due to the possibility of either a fire or explosion. The following table lists a number of facility damage costs, which have been extracted from references 1 and 2.

Table 7.21: Installation Damage Costs

Location	Type of Incident	Date	Cost	Type of Damage
Unknown	Well blowout and Fire, topsides destroyed	4/88	$325MM	Physical Damage costs only
North Sea	Explosion and destruction of platform Piper A	7/88	$160.0MM $680.0MM $100.0MM $275.0MM	Liability Physical Damage Removal costs Business interupt'n
Unknown	Explosion and fire during pipeline tie-in platform topsides destroyed	3/89	$120.0MM $350.0MM $50.0MM	Physical damage Business interupt'n Liability
Unknown	Gas explosion during riser ESDV installation	4/89	$25.5MM	Physical damage
Unknown	Platform fire and explosion	7/89	$3.7MM	Physical damage
Unknown	Platform struck by vessel causing blowout	12/89	$28.0MM $10.0MM $25.0MM	Physical damage Removal costs Business interupt'n
Norway	Sinking of Gravity Base Structure during trails	8/91	$400.0MM	Replacement costs
Gulf of Mexico	Hurricane Andrew damage	8/92	$250.0MM $307.5MM	Physical damage Business interupt'n

The above table illustrates the cost of installation damage and the variety in the range of these figures. Some of the large scales cost damage categories cover the well-known incidents such as Piper Alpha, Sliepner GBS sinking and Hurricane Andrew damage. The cost of damage to the facilities though has various constituent parts:

- Physical damage to the actual facility
- Removal costs
- Business Interruption costs
- Liability Damage.

Based upon the figures in the above table the cost of physical damage can be very high. The large-scale incidents do tend to dominate the overall cost structure. These costs tend to have four cost elements identified. Of the four major incidents the "Piper Alpha" disaster has a total cost of $1215MM and is to date the single largest offshore loss. A similar incident of the magnitude of the Piper Alpha disaster in the Gulf of Mexico facilities would be similar to the loss of a deepwater TLP or Spar facility with associated rebuilding costs around $500MM to $1000MM. Obviously the business interruption costs will differ from location to location but figures in the region of $250MM to $500MM would not seem unrealistic. Liability costs are likely to vary also but again the figure of $250MM to $500MM would not seem to be unrealistic. Removal costs are difficult to assess but the $100MM for the Piper Alpha would be on the high side due to the fact that large parts of the facility were recovered for the investigation. In the deep waters of the Gulf of Mexico such an effort may be unrealistic. Therefore the removal costs may be considered to be covered in the actual clean up costs. Based upon these estimates total values of between $1000MM and $2000MM would seem to be realistic for the extreme event were the facility was totally destroyed.

7.2.7 Limited Blowout Costs

Based upon the scale of the limited blowout costs there is only likely to be a negligible equipment damage and limited production loss, because if the blowout were to ignite it would be classed as a "major" blowout. Therefore for the purposes of this exercise the figure of $25.0 MM will be used as the risk cost figure for limited blowouts.

Using the above information a table of the likely cost contributors to the different events has been developed, see Table 7.22. This table is not all embracing but gives a general guide to the categories of cost included in the proposed figures. It should be clearly noted that these proposed figures are example figures used in the analysis of the three riser configurations.

Table 7.22: Example Cost Elements Included in Risk Cost Figures

Category of Cost	**Category of Release**		
Well Spill Costs	**Limited**	**Major**	**Extreme**
Mobilization of Equip't (e.g. Rig)	Yes	Yes	N/A
Separate MODU Rig Costs	Yes	Yes	Yes
Relief Well Drilling Costs	No	Possible	Yes
Re-Drill Original Well Costs	No	Possible	Yes
Spill Mobilization Costs	No	Yes	Yes
Mobilization of Emergency Equip't Costs	Yes	Yes	Yes
Specialist Blowout Contractor Costs	Yes (Limited)	Yes	Yes
Installation Damage Costs			
Damage to the Facility Costs	No	Yes if Ignites	Yes
Facility Clean up Costs	Yes	Yes	N/A
Debris Removal Costs (Topside modules)	Yes (partial)	Yes	Yes
Emergency Repair Costs	Yes	Yes	No (Total Loss)
Re-Design/Onshore Construction Costs	No	Yes (Modules)	Yes (Full Facility)
Offshore Installation and Hook up	No	Yes (Modules)	Yes (Full Facility)
Business Interruption (3rd Party)	No	Yes	Yes
Consequence Costs Used	**$25MM**	**$525MM**	**$3,750MM**

7.2.8 Major Blowout Costs

With the major blowout case the consequences would obviously be different depending upon whether the blowout ignites or not. If we take a 5000 bbls per day blowout for 30 days which if it ignited is likely to result in the total destruction of the facility with associated costs outlined above. If the blowout did not ignite the equipment and structural damage may be confined to extensive clean up of the facility. If the average blowout probability of ignition is 0.3 based upon historical figures and the cost of the facility in the extreme case is $1000MM. Combining these costs would give a figure of $600 MM based upon the following calculation ($375 MM + [$1000 MM * 0.3]). Alternatively if the blowout does not ignite the cost of $375 MM should be used. Taking a weighted average of these two costs this would give a figure of $488 MM as the value to be used for the Major blowout cost. This figure compares very closely to some of the costs associated with blowouts given in the above tables. On top of this value should be added some costs for business interruption. If we assume $25MM to $50MM depending upon the extent of the damage. This would give a value of $525MM.

7.2.9 Extreme Blowout Costs

If this figure for the loss of the installation is combined with the $2,250 MM clean up and outrage cost would give a value for an extreme event of between $3,250 MM to $4,250 MM with an average of $3,750MM. This obviously has made the implicit assumption that the blowout has ignited.

7.2.10 Conclusions

The consequence costs are primarily based upon the potential cost that would be incurred if a spill/release occurred, depending upon the size of the spill/release. Reference was made to data available on the size of release/spills and releases in the Gulf of Mexico, and a series of figures are proposed for both the "clean up" costs and the "outrage" costs on per barrel basis. The figures identified were generally around $1500 per barrel for "clean up" costs and $1000 per barrel for "outrage" costs. Once these figures had been identified the three sizes of spill/release "limited", "major" and "extreme" were defined as 1000 barrels per day for 10 days, 5000 barrels per day for 30 days, and 30,000 barrels per day for 30 days respectively. Using the release/spill costs identified the results of the analysis for the release sizes and duration identified were as follows:

- Limited $25MM
- Major $375MM
- Extreme $2250MM

In addition to the release/spill "clean up" and "outrage" costs for the "major" and "extreme" events potential damage to the facility should be taken into account. Again, reference was made to various costs, which involved damage to the facility and the possible cost drivers of, the physical damage, removal costs, business interruption, and liability damage. These costs were only taken into account for the "major" and "extreme" events. In the major category some modification of the figures was undertaken as a result of possible ignition and the ensuing damage, while in the "extreme" case it was assumed that the release would ignite and result in the total loss of the facility.

These additional costs were then added to the release "clean up" and "outrage" costs and the following total figures are proposed for use in the risk cost estimates.

Table 7.23: Proposed Consequence Costs

Event Size	Proposed Consequence Value $ MM*
Extreme	3750 MM
Major	525 MM
Limited	25 MM

*Note: These values are solely for the purpose of this study. Individual companies must determine their own values.

7.3 References

1. Insured Offshore Losses Greater than $1MM for the Period January 1988 to August 1990. Russ Johnson and Associates. London
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3. "Blowout Risks Cut with Contingency Plan" L W Abel of Wild Well Control Inc. Oil and Gas journal June 7th 1993
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6. "Guidelines For Chemical Process Quantified Risk Analysis" American Institute of Chemical Engineers, New York 1989 ISBN 0-8169-0402-2
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ATTACHMENT TO SECTION 7

1. FAULT TREE DRAWINGS
2. OPERATIONAL PROCEDURES / BARRIER LISTS

FAULT TREE DRAWINGS
(2 pages)

OPERATIONAL PROCEDURES / BARRIER LISTS
(2 pages)

8 RELIABILITY, AVAILABILITY AND MAINTAINABILITY EXPENDITURES, RAMEX

8.1 Introduction

During a well's life, components can fail that will require the well (and sometimes the entire system) to be shut-in while the component is being repaired. The cost to the operating company of this component failure is twofold:

- The cost to repair the component (i.e. repair vessel spread cost), and
- The lost production (if any) associated with one or more wells being down.

The average cost per year associated with these unforeseen repairs is called **r**eliability, **a**vailability, and **m**aintainability **ex**penditures, or RAMEX. The RAMEX of a particular component is calculated by multiplying the probability of a failure of the component (severe enough to warrant a workover) by the average consequence cost associated with the failure (repair and lost production costs). The system RAMEX is calculated by summing all of the component RAMEXs that are included in the particular system. This RAMEX cost is then factored into the overall Subsea Lifecycle Cost.

This section will illustrate the development of the RAMEX methodology by describing the following items:

- The calculation of the component reliability,
- The Reliability Block Diagram philosophy,
- Calculation of the system reliability,
- Calculation of the consequence costs for a particular scenario.

8.2 Component Reliability

This section discusses the following:

1. Definition of the completion system components.
2. Determination of failure modes and consequences of failures for each system component.
3. Determination of reliability data for each system component.

8.2.1 Define Completion System Components

A table of common well system components – from the tubing hanger to the reservoir - is developed for the five well tie-back completion systems (dual casing riser, single casing riser, tubing riser, conventional subsea tree, and horizontal subsea tree). The components considered are components that would warrant a workover if significantly failed.

The list of the components is shown in Table 8.1. Also listed for each component are the failure rates and repair types for each component. The determination of the failure rates is described in Section 8.2.4. The repair types listed are the following:

SFP	Workover - Sidetrack, Frac Pack (No. of)	TRE	Repair / Replace Subsea Tree*
SHZ	Workover - Sidetrack, Horizontal (No. of)	STR	Repair / Replace Platform Surface Tree
NFP	Workover - New Frac Pack (No. of)	CTO	Platform Coil Tubing Operation
CSL	Repair Completion System Leak		

These repair types correspond to the action required to repair the failed component. This is described further in Section 8.4.

Table 8.1: RAMEX System Components and Failure Rates

Component Failure	System(s)	Repair Type	Installation Failure Probability	Installation Probability of Extreme Fraction	Mean Time to Failure (years)	MTTF Probability of Extreme Fraction
Surface Christmas Tree/Master Valve EXL	DC, SC, TR	STR	0.006	0.05	30	0.05
Surface Christmas Tree/Master Valve FTC	DC, SC, TR	STR	0.00018	0.05	1000000	0.05
Subsea tree	CT, HT	TRE	0.002	1	30	1
Wellhead connector gasket leak	CT, HT	TRE	0.000001	1	1400	1
Tree connector test valve LCP	CT	TRE	0.0006	1	446	1
TH spool gasket leak	CT	CSL	0.000001	1	1400	0.05
Tubing hanger “spool tree” body leak	HT	TRE	0.000001	1	1400	1
High pressure cap	HT	TRE	0.00015	1	400	1
Tubing hanger plug	HT	CSL	0.01	0.5	100	0.2
Tubing Hanger Seals	DC, SC, CT, HT	STR – DT CSL – subsea	0.00001	0.1	300	0.1
Subsea Tubing Hanger Seals	TR	CSL	0.0001	0.05	127	0.05

Component Failure	System(s)	Repair Type	Installation Failure Probability	Installation Probability of Extreme Fraction	Mean Time to Failure (years)	MTTF Probability of Extreme Fraction
Tubing Hanger / Sfc WH penetration	DC, SC	STR	0.0006	0.05	50	0.05
Ch/SCSSV line penetr	DC, SC	STR	0.002	0.05	30	0.05
Tbg Jts - Srfc to SCSSV	DC, SC, TR, CT, HT	CSL	0.00002[1]	0.1	17000[1]	0.1
Tbg Jts (SCSSV to Pkr)	DC, SC, TR, CT, HT	CSL	0.00002[1]	0.1	17000[1]	0.1
Tbg Jts (Surface to mudline)	TR	TRE	0.00002[1]	0.1	17000[1]	0.1
Umbilical connector	TR	TRE	0.00002	0.05	800	0.05
Umbilical stab seals	TR	TRE	0.00002	0.02	242	0.05
Annulus Master valve FTC	TR	TRE	0.006	0.1	1000000	0.1
Subsea Master valve FTC	TR	TRE	0.006	0.2	1000000	0.2
Subsea Master valve EXL	TR	TRE	0.006	0.05	131	0.05
SCSSV FTC	DC, SC, TR, CT, HT	CTO – DT CSL – subsea	0.004	0.2	1000000	0.2
SCSSV EXL (e.g. control line)	DC, SC, TR, CT, HT	CSL	0.01	0.7	2200	0.05
Chemical Injection line	DC, SC, TR, CT, HT	CSL	0.001	0.05	380	0.05
Chemical Injection Valve	DC, SC, TR, CT, HT	CTO – DT CSL – subsea	0.05	0.5	100	0.05
Side Pocket Mandrel Leak	DC, SC, TR, CT, HT	CSL	0.01	0.1	250	0.1
Inst. Port Leak	DC, SC, TR, CT, HT	CSL	0.002	0.05	456	0.05
Anchor Tbg Seal Ass'y	DC, SC, TR, CT, HT	CSL	0.02	0.2	300	0.1
Permanent Packer	DC, SC, TR, CT, HT	CSL	0.006	0.85	330	0.2
Acid Stimulation	DC, SC, TR, CT, HT	CTO – DT CSL – subsea	0	1	40	1
Frac-Pack Completion[2]	DC, SC, TR, CT, HT	SFP	0.05	1	11	1
Horizontal (no gravel pack)[2]	DC, SC, TR, CT, HT	SHZ	0.1	1	6	1

[1] Failures are for a per joint basis
[2] Only one of these failures are counted for at a time – depending on the completion / workover type

8.2.2 Subsea System Equipment

Subsea completion equipment (i.e., manifolds, jumpers, etc.) can fail, resulting in production loss from one or more wells. Because these components can cause the downtime of more than one well, they are modeled separately from the downhole components.

The list of subsea system components and their failure rates modeled in this study is displayed in Table 8.2.

Table 8.2: Subsea Completion Equipment

Component Failure	Resource Type	Mean Time to Failure (years)
Pipeline EXL	Repair Pipeline or PLEM	23000[1]
PLEM valve	Repair Pipeline or PLEM	300
Jumper (Manifold to PLEM)	Repair / Replace Flowline Jumper	110
Manifold isolation valve EXL (x12)	Repair / Replace Well Subsea Choke	500
Umbilical (Hydraulic)	Repair / Replace Hydraulic System Umbilical	10000[1]
Hydraulic distribution Unit	Repair / Replace Hydraulic System Umbilical	80
Umbilical (Electrical)	Repair / Replace Electrical System Umbilical	8000[1]
Electrical Distribution unit	Repair / Replace Electrical System Umbilical	50
Jumper (Manifold to tree)	Repair/ Replace Tree Jumper	35
Flying Lead Electrical	Repair / Replace Well Flying Leads	50
Flying Lead Hydraulic	Repair / Replace Well Flying Leads	80
Control pod	Repair / Replace Well Control Pod	18
Choke (erosion/wear)	Repair / Replace Well Subsea Choke	15
Extension Pipeline EXL	Repair Extension Pipeline or PLEM only if > 8 wells	23000[1]
Extension PLEM valve	Repair Extension Pipeline or PLEM only if > 8 wells	300
Extension Jumper (Manifold to PLEM)	Repair / Replace Extension Jumper only if > 8 wells	110
Extension Manifold isolation valve EXL (x12)	Repair / Replace Well Subsea Choke	1000
Extension Umbilical (Hydraulic)	Repair / Replace Hydraulic Extension Umbilical only if > 8 wells	10000[1]
Extension Hydraulic distribution Unit	Repair / Replace Hydraulic Extension Umbilical only if > 8 wells	80
Extension Umbilical (Electrical)	Repair / Replace Electrical Extension Umbilical only if > 8 wells	8000[1]
Extension Electrical Distribution unit	Repair / Replace Electrical Extension Umbilical only if > 8 wells	50
Extension Well Jumper (Manifold to tree)	Repair / Replace Extension Jumper only if > 8 wells	35

[1] Failures listed are a per joint basis

The subsea system equipment are only used with subsea wells (and not with dry tree wells) and all of the subsea wells utilize the subsea system equipment. In order to distribute the failures of the subsea system equipment, the risk costs for the subsea system equipment are divided among the number of subsea wells and summed with the risk costs for the downhole equipment associated with those particular wells.

8.2.3 Determine Failure Modes and Failure Consequences for Each System Component

The critical failure modes (mechanical failure, reservoir-related failures, and regulatory driven shutdowns) and the associated consequences of the failures for common well system components are identified. An FMECA (Failure Mode, Effect and Criticality Analysis) approach is used to facilitate this process.

Each failure mode is evaluated by the FMECA group to determine the probability of occurrence and severity of consequence based on the participants' experience. In this process it is important to identify:

- How a failure would be repaired (rig, wireline, or coiled tubing)
- What types of repair resources are required to accomplish the repair
- The availability time for repair resources
- The well production rate lost while waiting on repair resources
- The duration of the repair activity

This information provides an initial basis for the overall reliability and consequence estimates that can be refined by more detailed analyses at a later stage.

8.2.4 Determine Reliability Data for Each Component

8.2.4.1 Definition of Reliability

Reliability is the probability that an item will perform a required function under stated conditions for a stated period of time. For this project, most failures are caused by leaks in the completion system (leak to the annulus) that require a workover or a failure in a subsea production system component. An exception is a paraffin plugging that requires a wireline or coiled tubing intervention to remove the paraffin. Another exception is a sand control system failure that requires a workover to re-install the sand control system.

The user has the option to specify that oil production from a well is either totally shutdown (100% production cut back) while waiting on a rig or is only partially cut back (for example 40%) during this waiting time. The well production is totally shutdown (100% production cut back) during well intervention.

8.2.4.2 Reliability Analysis

Reliability analysis involves an iterative process of reliability assessment and improvement, and the relationship between these two aspects is important. In some cases the assessment shows that the system is sufficiently reliable. In other cases the reliability is found to be inadequate, but the assessment work reveals ways in which the reliability can be improved. It is generally agreed that the value of reliability assessment lies not in the figure obtained for system reliability, but in the discovery of the ways in which system reliability can be improved.

8.2.4.3 Reliability Parameters

This project has adopted the component leak reliability data concept that was developed in the Joint Industry Project Dry Tree Tieback Alternatives Study (DTTAS)[1], which includes a comprehensive set of completion component reliabilities. Reliabilities of individual components are represented by the following four types of data:

- probability of failure due to installation failures
- probability that the failure is extreme given that the installation failure occurs

[1] The Dry Tree Tieback Alternative Study was a Joint Industry Study that developed and demonstrated a methodology to calculate Risk of Blowouts from alternative completion systems.

- mean time between failures for failures that occur after installation period (assuming constant failure rate/exponentially distributed failure times)
- probability that a failure is extreme given that the failure occurs after installation period (constant failure rate/exponentially distributed failure times).

All failures of all magnitudes are represented by these data. This includes failures that are due to mechanical failures, human factors, incorrect designs or improper installation procedures, and environmental or operational causes. Statistical data that are known to include only certain types of failures have to the extent possible been corrected to include all failures.

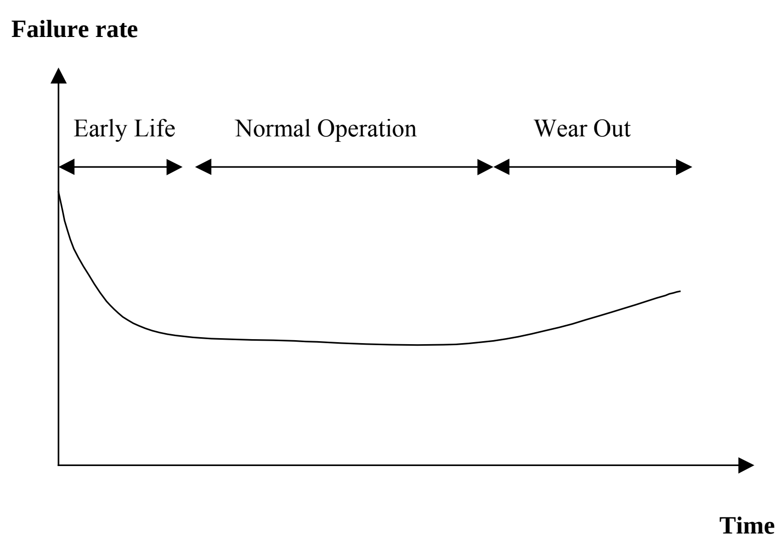
An "installation failure probability" is used in combination with a time dependent probability (exponentially or histogram distributed failure times) to better describe the "lifetime reliability" of the completion components.

In addition to the DTTAS data, several other data sources have been used to develop the overall data set used in this study.

8.2.4.4 Lifetime Reliabilities - The Bath Tub Curve

According to classical reliability theory, equipment failures typically exhibit three stages of failure behavior during their lifetime. This "lifetime" reliability is illustrated by the "Bathtub" curve shown in the Figure 8.1 below. Initially ("Early Life/Infant Mortality"), the failure rate decreases reflecting discovery and replacement of defective components, incorrect installation and the learning curve of the component user. Then after the installation period ("Normal Operation"), failures occur at a fairly constant rate ("Random Failures"), and finally, the failure rate increases as wear, corrosion, erosion, and other deterioration sets in ("Wear Out").

Figure 8.1: The Classical Bath Tub Curve



Well systems are observed to follow a similar failure behavior. Failure rates are high when well systems are initially installed and after workover operations. During normal (long-term) production operation, the failure rates are generally low. For high rate, deepwater developments, zone depletion occurs long before failure rates start to increase due to wear or deterioration.

8.2.4.5 *Early Life*

Early failures are usually due to such factors as defective equipment, damaged seals, incorrect installation and inadequate testing. Defects that are detected during completion and workover operations only extend the time and cost of these operations and are part of historic consequence cost data (downtime data). The installation probability of failure accounts for early failures that are undetected until after the repair resource is released from the well.

The mathematical representation of these installation probabilities are summarized as follows:

$P(0)$ = *installation probability of (any) failure*

$P_{EF|I}$ = *probability of extreme failure, given that an installation failure occurs.*

$P_{EF}(0)$ = *probability of extreme installation failure*

$$P_{EF}(0) = P(0)*P_{EF|I}$$

It is relatively common to have failures of completion components during their installation because of the difficulty of installing downhole components. Completion components often leak because of minor seal damage, imperfect make-up, failure of inspection methods to detect all seal damage, and failure of testing to reveal all leaks.

Installation Probability Example

A typical installation failure probability of a tubing joint is about two in one hundred thousand joints, i.e. 2×10^{-5}. However, only about one in ten of the leaks that do occur due to installation failures are extreme. The probability of extreme leaks is:

$$P_{EF}(0) = P(0)*P_{EF|I}$$
$$= 0.00002 * 0.1 = 0.000002 \quad (2.0 \times 10^{-6})$$

The probability of a limited leak is:

$$P_{LF}(0) = P(0)*(1 - P_{EF|I})$$
$$= 0.00002 * 0.9 = 0.000018. \quad (1.8 \times 10^{-5})$$

These values were developed in the DTTAS as an average of judgement from several completion specialists (expert judgment).

We believe that all extreme leaks constitute a barrier failure that requires a workover. We reason that part of the limited leaks is sufficiently small (at least initially) to permit any resulting annulus pressure to be bled off in accordance to MMS regulations (see Section 8.2.4.8).

8.2.4.6 Long Term Failure Rates

The middle portion of the bathtub curve ("Normal Operation") is either modeled with constant failure rate (exponential distribution) or variable failure rate (histogram distribution). This accounts for failures that occur after the installation period ("Early Life").

<u>*Exponential Distribution - Constant Failure Rate*</u>

Most commercial reliability databases assume a constant failure rate. The "constant" or so-called "random" failure often occurs when a number of failure mechanisms are involved and each individually exhibit a different failure distribution. When these individual distributions are aggregated together, the overall failure distribution of the system will appear random (constant).

Constant rate of failures, λ, (failures per unit time) is the reciprocal of Mean Time Between Failures, MTTF (time units per failure). The "age related reliability", R(t), at time, t, is:

$$R(t) = e^{-\lambda t} \text{ or } R(t) = e^{-t / MTBF}$$

The MTTF data for each component represent the exponential decline rate for that component's reliability. The mathematical representation of these constant failure rate probabilities at time, t, is summarized in the following definitions. As with the installation reliabilities, this study is concerned with all extreme leak failures and a portion of limited leaks that require a workover.

P(t) = probability of an extreme leak within time "t".

$= 1 - R(t) = 1 - e^{-t / MTTF}$

$P_{EF}(t) = P(t) * P_{EF|R}$

where:

R(t) = reliability at time "t", i.e. $e^{-t / MTTF}$*, probability of surviving time "t"*

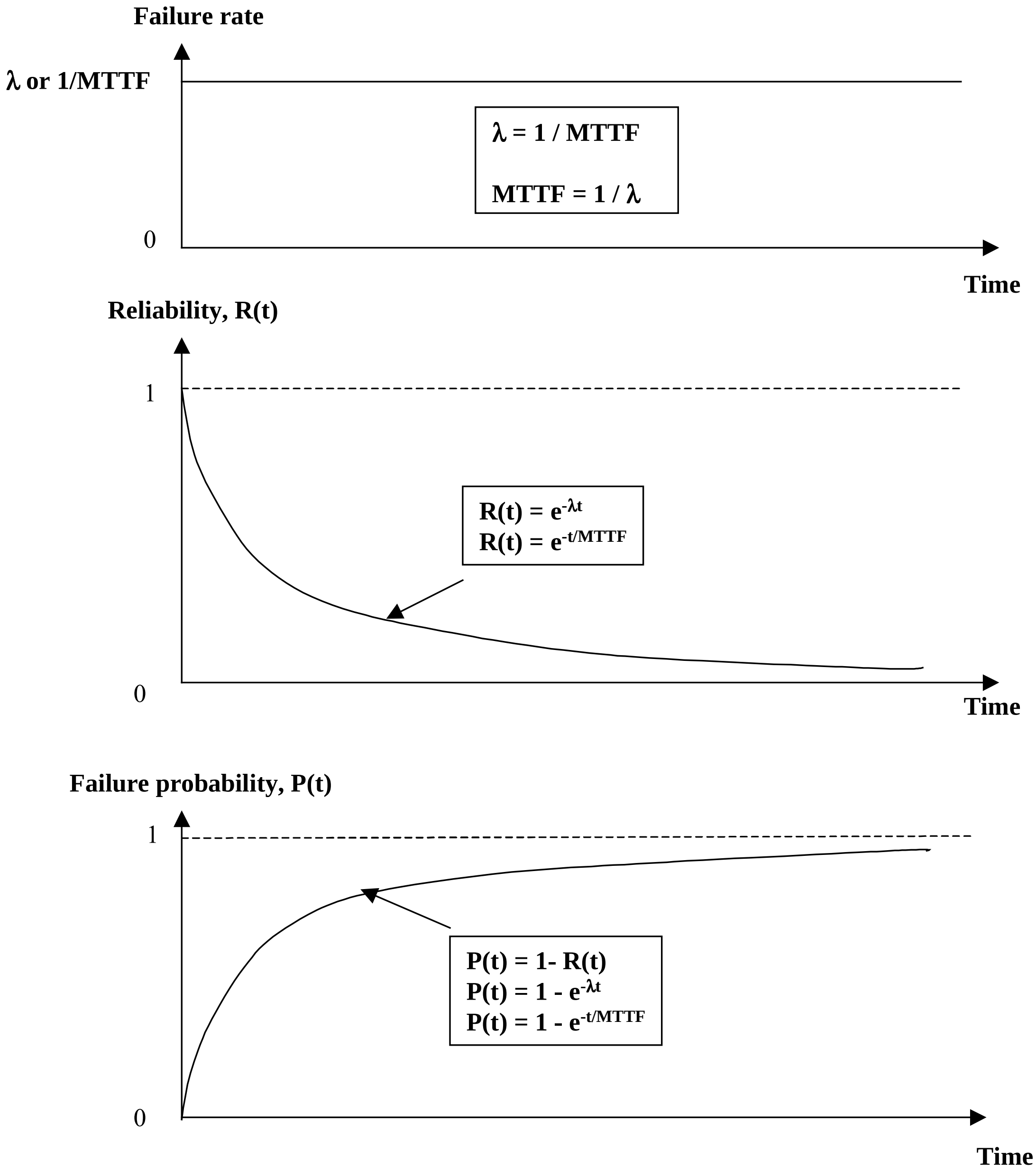
MTTF = mean time to failures

$P_{EF|R}$ *= probability of extreme failure, given that a random failure occurs*

$P_{EF}(t)$ *= probability of extreme failure within time "t",*

The negative exponential distribution is illustrated in Figure 8.2.

Figure 8.2: Failure Time Distribution – Exponential



<u>Constant Failure Rate Probability Example</u>

An MTTF for a tubing joint is about 17,000 years per failure. However, only about one in ten of the leaks that do occur are extreme. The constant failure rate probability of failure that requires an immediate workover is:

$$P_{EF}(t) = P(t)*P_{EF|R}$$
$$= (1 - e^{-t/17,000}) * 0.1$$

This probability of failure is a function of the time since the component was installed. For a ten year duration, this probability is:

$$P_{EF}(10\ years) = (1 - e^{-10/17,000})* 0.1$$
$$= (1 – 0.99941) * 0.1 = 0.0000588 \qquad (5.88 \times 10^{-5})$$

8.2.4.7 Wear-Out and Deterioration Increasing Failure Rates

As the life of the component increases eventually “wear out” will dominate. This is where the failure rate increases significantly with time. However, this type of failure is not expected during the field life of the high rate deepwater completions considered in this study. It is assumed that the components are designed for the required lifetime.

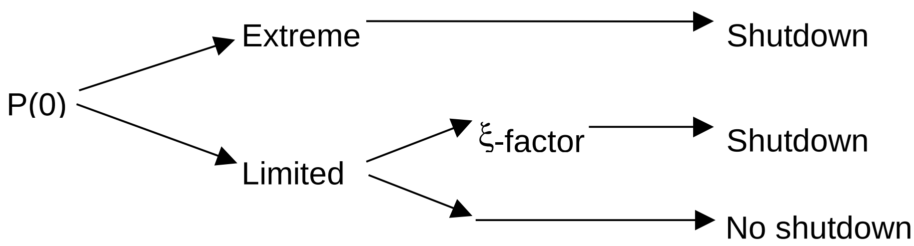
8.2.4.8 Limited Component Failure

As discussed previously, the component failures are divided into two regimes: limited and extreme. This division of limited and extreme leaks is based on the observation that many completion components either fail catastrophically or small leaks occur and then gradually increase in size. For example, a packer may not set, resulting in an extreme leak; or a packer bore seal assembly may develop a limited leak due to sea deterioration and wear. Tubulars may fail catastrophically due to a failed weld or develop a limited thread leak in the connection.

All extreme failures are assumed to necessitate a workover. However, a limited failure may or may not cause a stoppage of operations, depending on the size and nature of the failure. Small leaks often cause pressures to increase in the annulus between the tubing string and the production casing. The U.S. Minerals Management Service (MMS) permits producing operation to continue with annulus pressure so long as the pressure build-up is within certain limits. Leaks that are sufficiently small to permit continued operations may eventually increase in size until sustained annular pressure indicate loss of a well control barrier.

For this analysis, the percentage of limited failures that will be severe enough to create the need to workover the well is called the ξ-factor. The failure breakdown is shown in Figure 8.3.

Figure 8.3: Failure Breakdown that Causes a Workover



The components for which the ξ-factor is used as a factor are the following:

- Tubing hanger seals
- Tubing joints
- SCSSV external leak
- Side pocket mandrel leak
- Instrument port leak
- Anchor tubing seal assembly
- Permanent packer leak

Using the ξ-factor, the probability of failure upon installation is calculated through the use of the following equation:

$$P_{inst} = 1-[1-(P(0) * P_{EF/l})]*[1-(P(0)*(1-P_{EF/l})* \xi)]$$

where:

P_{inst} = *the total component failure probability used in the model (all extreme failures and a portion of the limited failures)*

ξ = *the percentage of limited failures that will necessitate a workover*

The long term failures that incorporate the ξ-factor are calculated in a similar fashion:

$$P_a(t) = 1 - R(t) = 1 - e^{-t / MTTFa}$$

$$MTTF_a = \frac{1}{\left(\dfrac{1}{\left(\dfrac{MTTF}{P_{EF/I}}\right)}\right) + \left(\dfrac{1}{\left(\dfrac{MTTF}{(1-P_{EF/I})*\xi}\right)}\right)}$$

where:

$P_a(t)$ = *the probability of failure that will cause a workover within time (t)*

$MTTF_a$ = *the Mean Time To Failure that will necessitate a workover*

8.2.4.9 ξ-factor Determination

The ξ-factor was determined through a systematic trial and error method. The ξ-factor was adjusted until the resulting number of workovers / well-year was a value that compared well with historical failures. Historically speaking, the number of workovers/well-year that resulted from a leak from the production tubing to the annulus is 2 failures per 120 well-years. Based on this value, a ξ-factor of 0.3 is appropriate.

A leak from the tubing riser to the annulus in a single casing riser system will result in the need for a workover, regardless of the size of the leak. This is per MMS standard practices. Because of this, a ξ-factor of 1 is used for the single casing system.

8.2.4.10 Combined Installation and Constant Failure Rate Probability Example

The probability of leaks that require workovers is:

$$P_{E/CF}(t) = 1 - \{[1 - P_{inst}] * [1 - (1 - e^{-t\,/\,MTBFa})]\}$$

For the packer example calculated above, the probability of failure after installation and ten years of operation is, assumed a ξ-factor of 30%:

$$P_{inst} = 1 - \{[1\text{-}(0.00002)*0.1]*[1\text{-}(0.00002*0.9*0.3)]\} = 0.0000074\ (7.4 \times 10^{-6})$$

$$MTTF_a = \{(17000/0.1)^{-1} + [17000/(0.9*0.3)]^{-1}\}^{-1} = 45{,}946 \text{ years}$$

$$P_a(10 \text{ years}) = 1\text{-}\{[1\text{-}0.000011]*1\text{-}(1\text{-}e^{-10/45{,}946})]\} = 0.00022\ (2.2 \times 10^{-4})$$

8.2.4.11 Seal Ranking

Several sources of data have been used to compile the data set of individual completion component reliabilities. Individual seal types, installation difficulty (based on installation procedures) and operating conditions were considered to rank the seal reliabilities. This ranking of seal reliabilities provides a check of the sometime limited statistical data, and it provides a basis for *developing* reliability data for components where data are nonexistent by interpolating between statistical "accurate" reliabilities.

It is recommended that a seal-ranking table be used to provide a "reality check" when selecting appropriate reliability data for new components. Also, a seal-ranking table should be used in sensitivity studies, when alternative reliability data are used to determine the differences in overall production loss and repair costs that result from changes in the reliability of individual completion system component reliabilities.

Table 8.3 describes the ranking system used in the DTTAS. This table considers factors such the seal type (elastomeric or metal), seal sub-type (single seal or multiple seals) and how the seal is installed (surface or downhole). Additional factors may be considered in this reality check to ensure that the selected reliability data values are reasonable.

Table 8.3: Seal Ranking

Seal Type	Seal Sub-type	Installed	Example	Rank
Pipe or valve Body Welded connection	None	Manufactured from forging Welded pipe using certified welder and procedures	Pipe body Valve body or X-mas tree Pipe length	Best
Metal to Metal	Pressure Energized Seal Ring	Hydraulic Operator Actuated Surface Installed and Tested	Subsea Wellhead connector API Flange Connection	Excellent
Metal to Metal	Multiple Metal to Metal Seals Shouldered Interference	Surface installed and tested Surface installed and tested	Premium Tubulars Manufacturers' Shop Connections	Excellent
Wellhead Sandwich Packing	Energized by Casing Weight	Multiple Seals Installed and Tested	Conventional Surface Wellhead Packing	Excellent
Static Elastomers	Elastomers with back-up Elastomer without back up	Surface installed Running String Set	Permanent Packer Element Surface Set Gas Lift Valves Retrievable Packers and Test Packers Packer Bore seals	Good
Dynamic Elastomers	Elastomers with back-up Elastomer without back up	Shop makeup-machined parts Surface Installed and Tested Downhole installed / Tested	SCSSV Internal Seals Packer Bore Seals	Fair
Wireline Set Chevron Packing	Static	Downhole Set	Side Pocket Mandrel Packing	Worst

8.2.4.12 Uncertainties

When system failure performance is modeled as a stochastic phenomenon there will always be uncertainties associated with the results. Uncertainty, as applied in this study, is defined as the degree of imprecision that is attached to parameters in the Reliability Assessment. The "true" value of the parameter can not be known; only estimates are available. The uncertainty attached to the estimates explicitly acknowledges this difference.

Main sources of uncertainty are as follows:

1. *Uncertainty related to whether the events will occur within a given time period.* For instance, how many of the identified events critical from a risk point of view will actually occur during the lifetime compared to the ones that could occur. This is actually quantified in terms of probabilities - and thus the probabilities are used to "measure" uncertainty instead of being uncertain themselves.
2. *Uncertainty in the reliability data.* The information leading up to a predicted likelihood of occurrence for a critical event ("frequency of occurrence" or "failure rate") may be limited. The analyst, due to limited information, may not be able to attribute the identified events with the "correct" set of properties. This could be due to the use of data which are not representative for the type of equipment analyzed (design, technology, age, frequency trends, etc.), insufficient observation time, or the fact that the data have been extracted from operating and environmental conditions which is not representative.
3. *Insufficient system information and modeling inaccuracy.* Due to insufficient system information the reliability analysis must be based on a number of assumptions and conditions. The identified critical events that form the basis for the input to a reliability analysis do not represent the complete picture of all possible events that can influence the operation of the completion systems. The reliability analysis has to make assumption and modeling short-cuts to fit a model to a real situation. Omission of critical components/events leads to over-estimate of reliability and possibly to under-valuing reliability increasing measures.

The underlying failure mechanisms for the various *components* are used to predict certain *system* performance attributes. The three elements listed above all relate to the degree of precision that could be obtained in the estimated performance attributes.

8.2.4.13 Data Sources

Component reliability data are mainly obtained from the following sources:

- General industry data banks (WellMaster, OREDA, WOAD, E&P Forum).
- Data surveys conducted as part of this study and previous studies.
- DNV internal data.
- Expert judgment.
- Ranking methods.

Expert judgement was used to establish or modify historical component reliability data where historical data were unavailable or sparse.

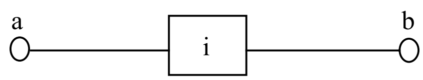
8.3 Reliability Block Diagrams

This section illustrates how the structure of a system can be represented by a *Reliability Block Diagram (RBD)*. The term *Reliability* is defined below.

8.3.1 Graphical Representation

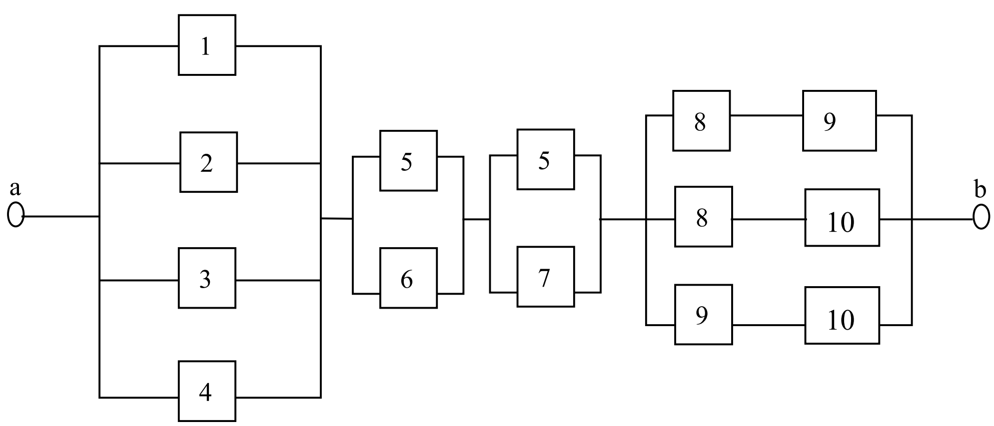
A reliability block diagram (RBD) analysis is a deductive (top-down) method. An RBD is the graphical representation of a system's logical structure in terms of sub-systems and components. The RBD allows the system success paths to be represented by the way in which the sub-systems and components are logically connected. An RBD is appropriate to model one system function only. If the system has more than one function, each function is considered individually, and a separate RBD is established for each system function.
Consider a system with *n* different components. Each of the *n* components is illustrated by a block as shown in Figure 8.4.

Figure 8.4: Component *i* Illustrated by a Block



When there is connection between the end points (*a*) and (*b*) as in Figure 8.4 component *i* is considered functioning as designed. This does not necessarily mean that component *i* functions in all respects. It only means that one, or a specified set of functions, is achieved (i.e., that some specified failure mode(s) do not occur). What is meant by functioning must be specified in each case and will depend on the objectives of the study.
The way the *n* components are interconnected to fulfill a specified system function may be illustrated by a reliability block diagram, as shown in Figure 8.5. The specific system function is considered achieved, when there is a connection between the end points (*a*) and (*b*) in Figure 8.5, which means that some specified system failure mode(s) do(es) not occur.

Figure 8.5: System Function Illustrated by a Reliability Block Diagram



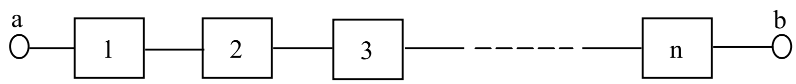
It should be emphasized that a reliability block diagram is not a physical layout diagram for the system. It is a logic diagram, illustrating the function of the system.

8.3.2 Non-repairable Series Structure

A system that functions only if all of its n components are functioning is called a *series structure*.

In a series system the system fails to function if any one of the components in series fails to perform its required function, over the specified period of time. It is not implied that the components are necessarily laid out physically in a series configuration. The corresponding reliability block diagram is shown in Figure 8.6. “Connection” between the end points (*a*) and (*b*) (i.e. the system is functioning) is achieved only if there is “connection” through all the *n* blocks representing the components.

Figure 8.6: Reliability Block Diagram of a Series Structure



The reliability function of such a system is the product of the reliabilities R_i of the components.

$$R_{system} = \prod_{i=1}^{n} R_i$$

In other words: “A chain is no stronger than it’s weakest link”.

When using the exponential distribution (the failure rates λ_i of the components are constant) the reliability of individual components that is not repaired is:

$$R_i = \exp(-\lambda_i t)$$

and therefore the reliability (survivor function) of a non-repairable system of “n” components is:

$$R_{system} = \prod_{i=1}^{n} \exp(-\lambda_i t) = \exp(-\sum_{i=1}^{n} \lambda_i t)$$

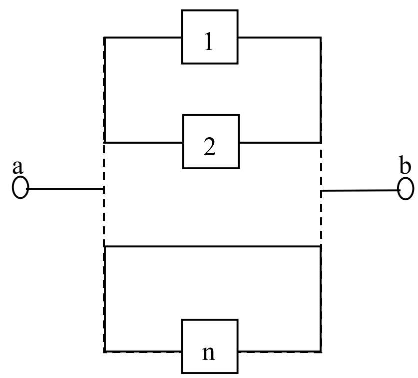
This means that the reliability of a series system follows an exponential distribution if each of the n components have exponentially distributed lifetimes. The failure rate of such a system is the sum of the n component failure rates. The mean time to failure (MTTF) is:

$$\mathrm{MTTF} = \int_0^\infty \mathrm{R}_{\mathrm{system}}(\mathrm{t})\mathrm{dt} = \int_0^\infty e^{-\sum_{i=1}^{n}\lambda_i \mathrm{t}}\, dt = \frac{1}{\sum_{i=1}^{n} \lambda_i}$$

8.3.3 Non-repairable Parallel Structure

A system that is functioning if at least one of its n components is functioning (or one that fails to operate only if all its components fail to operate) is called a *parallel structure*. The corresponding reliability block diagram is shown in Figure 8.7. In this case "connection" between the end points (*a*) and (*b*) (i.e., the system is functioning) is achieved if there is "connection" through at least one of the blocks representing the components.

Figure 8.7: Reliability Block Diagram of a Parallel Structure



Again it is not implied that the components are necessarily laid out physically in a parallel configuration.

The reliability of a parallel system is:

$$R = 1 - \prod_{i=1}^{n} (1 - R_i)$$

where:

$R_i = exp(-\lambda_i t)$

Since parallel configurations incorporate redundancy, they are also referred to as "parallel redundant systems." For parallel non-repairable systems where the exponential distribution applies the reliability (survivor function) is given by:

$$R_{system} = 1 - \prod_{i=1}^{n} [1 - exp(-\lambda_i t)]$$

For parallel systems there is no simple general relationship between the system failure rate and the component failure rates. It should also be noted that the reliability of a parallel system does not follow an exponential distribution although the individual components have exponentially distributed lifetimes.

The mean time to failure of two components in parallel is:

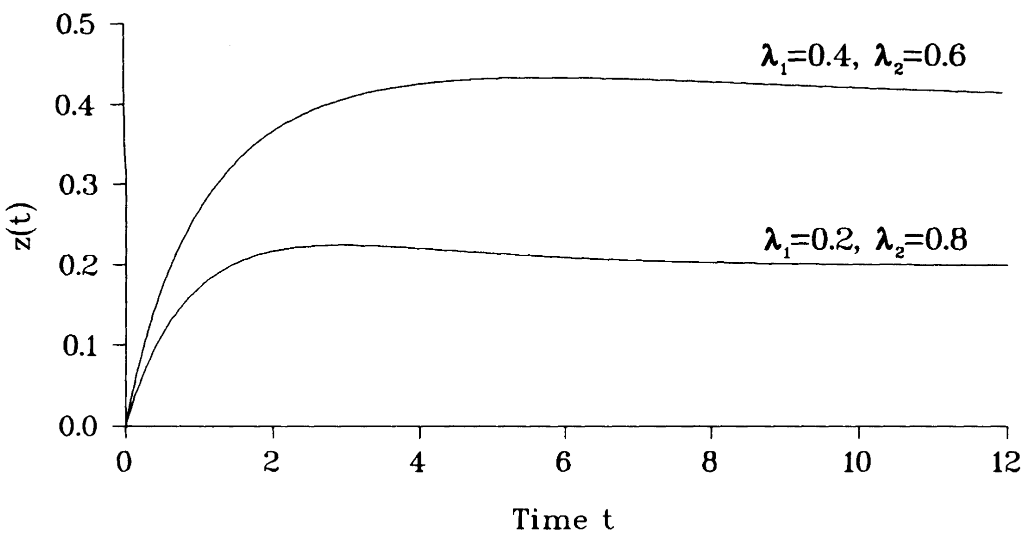
$$MTTF = \int_0^\infty R_S(t)dt = \frac{1}{\lambda_1} + \frac{1}{\lambda_2} - \frac{1}{\lambda_1 + \lambda_2}$$

The failure rate *z(t)* is:

$$z(t) = \frac{\lambda_1 e^{-\lambda_1 t} + \lambda_2 e^{-\lambda_2 t} - (\lambda_1 + \lambda_2) e^{-(\lambda_1 + \lambda_2)t}}{e^{-\lambda_1 t} + e^{-\lambda_2 t} - e^{-(\lambda_1 + \lambda_2)t}}$$

It is now easy to find a time t_0 so that *z(t)* is increasing in the interval (0, t_0)while *z(t)* is decreasing in the interval (t_0,∞). This t_0 will depend on λ_1 and λ_2. In Figure 8.8, *z(t)* is sketched for selected combinations of λ_1 and λ_2, such that $\lambda_1 + \lambda_2 = 1$.

Figure 8.8: Failure Rate for Parallel Structure ($\lambda_1 + \lambda_2 = 1$)



This example illustrates that even if the individual components of a system have constant failure rates (i.e., $z_1(t)=1/MTTF_1$, $z_2(t)=1/MTTF_2$), the system itself may not have a constant failure rate.

8.3.4 Repairable Systems

If possible, components and systems are usually replaced or repaired after a failure. Usually one distinguishes between two types of maintenance: corrective and preventive maintenance.

Corrective maintenance is usually called repair; it is carried out after a component has failed. The purpose of the corrective maintenance is to bring the component back to a functioning state as soon as possible.

Preventive maintenance seeks to reduce the probability of failure of a component. It may involve procedures such as adjustment or replacement of components that are beginning to wear out. Periodic testing and maintenance based on condition monitoring are also regarded as preventive maintenance.

For repairable systems the term "Availability" is often used as the reliability performance factor (as the survivor function for non-repairable systems). The availability is defined as the probability of functioning at a given time *t*. However, for practical purposes the *average* availability is normally used and is defined as the fraction of time an item is able to perform its intended function. In situations where the failure will be discovered immediately, the average availability is defined by:

$$A = \frac{MTTF}{MTTF + MTTR} = \frac{MTTF}{MTBF} \overset{*}{\approx} 1 - \frac{MTTR}{MTTF}$$

where:

MTTF = Mean Time To Failure = The expected time an item is able to perform its intended function

MTBF = Mean Time Between Failure

MTTR = Mean Time To Repair
* when MTTF >> MTTR

The graphical interpretation of this formula is given in Figure 8.9.

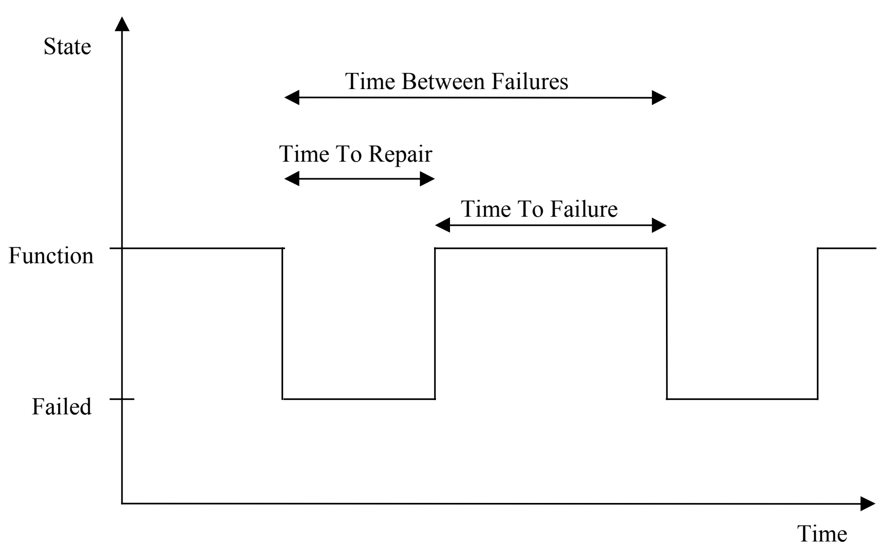
In situations where the failure will be discovered only during testing, the average availability is defined by:

$$\mathrm{A} = \frac{\mathrm{MTTF}}{\mathrm{MTTF} + \mathrm{MTTR} + \frac{1}{2}\tau}$$

Where τ is the time between tests.

Its should be noted that the instantaneous availability will converge rapidly toward the average availability for most lifetime and downtime distributions.

Figure 8.9: Failure And Repair Times



For instance if a control pod has a mean time to failure, MTTF= 150 000 hours (~17 year), and a mean repair time, MTTR = 132 hours (~5.5 days), the average availability is 0.9991 = 99.91% which corresponds to approximately 7.7 hours of downtime per year on average.

In case repair resources are not available on site the time spent to mobilize a repair resource to the site where it is needed and to get it ready for repair work should also be taken into account. The following definitions have been used in this study:

Downtime: The total time an item has been out of service due to a failure including, but not restricted to the time to detect the failure, delays and waiting time, active repair time and time for testing and start up after repair.

Availability Time: The time spent to get a repair resource to the site where it is needed and to get it ready for repair work.

Repair Time: Time required to locate the failure, repair and return the item to a state where it is ready to resume its functions. This excludes planned delays and waiting for spares or tools.

Repair Resource: Vessel, tool; equipment and manpower required to perform a repair or maintenance action.

Unavailability: The unavailability is defined as 1-Availability, i.e. the fraction of time an item is not able to perform its intended function.

For a series system with *n* independent components the availability could be approximated by the following formula:

$$A_{system} = \prod_{i=1}^{n} A_i$$

For a parallel system with *n* independent components the availability could be approximated by the following formula:

$$A_{system} = 1 - \prod_{i=1}^{n} (1 - A_i) = 1 - \prod_{i=1}^{n} U_i$$

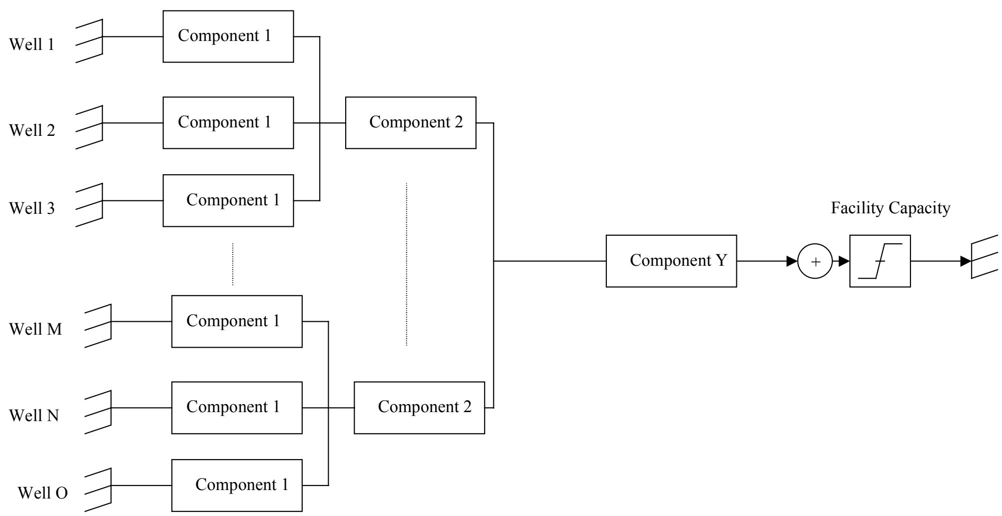
8.4 System Reliability

8.4.1 Introduction to the Calculation Approach

A completion system is defined as a simplified, hierarchical network of completion components. The completion system can consist of one or more wells; the well can consist of one or more completion components.

A well is defined as a list of completion components, their failure modes, the corresponding consequences in terms of reduced production, and the required repair resource. A well is considered to function if all of its components are functioning (in reliability theory referred to as a series structure). The type and number of completion components may vary from well to well. This modeling principle is illustrated in Figure 8.10.

Figure 8.10: Block Diagram Illustration of the Simulation Model



8.4.2 Failure Probabilities

8.4.2.1 Calculations

The calculation methods described in Section 9.2 will determine the probabilities of a component failing *by* that particular year. In order to determine the *individual* annual failure probabilities (i.e. the probability that the component will fail during a particular year) for the system, the following equation is used:

$$P_{year} = \frac{P_a(H) - P_a(L)}{1\text{ year}}$$

where:

$P_a(H)$ = the probability of component failure for the end of the year (e.g., 2 for year 1)

$P_a(L)$ = the probability of component failure for the beginning of the year (e.g., 1 for year 1)

These individual annual failure probabilities are combined using the reliability block diagram techniques described in Section 8.3 to determine the annual system failure probability. The annual system failure probability is then used to calculate the downtime and repair risk costs.

8.4.2.2 Workover Frequency

It is assumed that when the well is worked over, the old well equipment will be replaced with new equipment. Thus, when the well receives a workover, the failure probabilities for the new well will be the same as the initial well installation.

The workover frequencies are determined from the production profile produced when running the main program. When a workover is performed in the middle of the year, the failure probability is taken to be the weighted average of the failure probability of the old equipment and the failure probability of the new equipment (depending on when in the year the workover is performed). This concept is described further in Figure 8.11.

Figure 8.11: Annual Failure Probabilities with Workovers

Workover @ 3.7 years

Workover @ 6.5 years

Year

1	2	3	4	5	6	7	8	9
$P_{year\ 1}$	$P_{year\ 2}$	$P_{year\ 3}$	$P_{year\ 4}$ * 0.7 + $P_{year\ 1}$ * 0.3	$P_{year\ 1}$ * 0.7 + $P_{year\ 2}$ * 0.3	$P_{year\ 2}$ * 0.7 + $P_{year\ 3}$ * 0.3	$P_{year\ 3}$ * 0.5 + $P_{year\ 1}$ * 0.5	$P_{year\ 1}$ * 0.5 + $P_{year\ 2}$ * 0.5	$P_{year\ 2}$ * 0.5 + $P_{year\ 3}$ * 0.5

8.4.3 Unplanned Workover Frequency Calculation

The number of unplanned workovers can be calculated using the RAMEX methodology. Each component failure mode has a specific workover associated with its repair. Using the component failure probabilities described earlier, it is then possible to determine the frequency per year of each unplanned workover.

The unplanned workover frequencies that are calculated are:

- Coil tubing / wireline operations
- Sand control repair (new frac pack)
- Downhole tubing repair
- Subsea tree repair / replace

These frequencies are then used as inputs for the RISKEX calculations.

8.5 Consequence Costs

RAMEX is calculated by multiplying the yearly system failure probability of the system by the costs associated with lost production and repairing the system for the particular failure. This section will first describe the calculation of the lost production costs, then describe the repair costs.

8.5.1 Lost Production Costs

The consequences in terms of lost/delayed production are divided into:

- Consequence in terms of the volume produced per time unit from an individual well.
- Consequence for the volume exported per time unit from the surface facility.

The oil/gas production profiles vary over time. Each individual well will have a normal production rate, which sums to the normal daily field production rate. The individual well capacity can be larger than the normal rate.

The production consequence for an individual well depends on the following:

- The production rate at the time the failure occurred
- Lost capacity while waiting on repair resources
- Availability time for the repair resources
- Active repair time

The average production loss per year due to any particular component is given by the following equation:

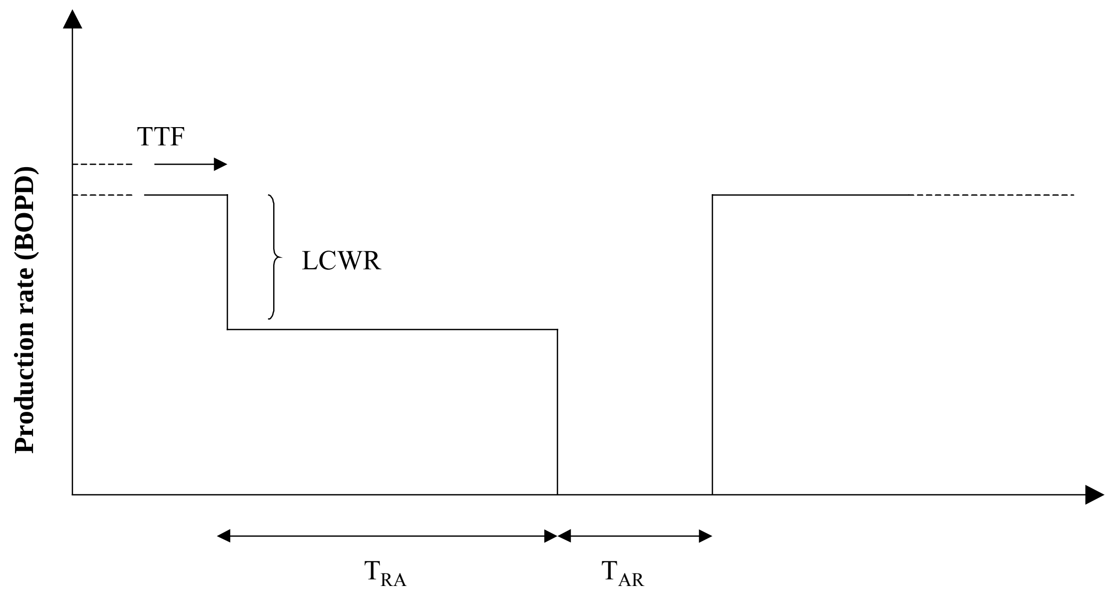
$$PL_{year} = \frac{P_a(H) - P_a(L)}{1\text{ year}} * (T_{AR} + T_{RA}) * PR * 365\text{ days/year}$$

where:

PL_{year} = the production loss cost for a given year
$P_a(H)$ = the probability of component failure for the end of the year (e.g. 2 for year 1)
$P_a(L)$ = the probability of component failure for the beginning of the year (e.g. 1 for year 1)
T_{AR} = the mean time to repair a certain failure
T_{RA} = the rig availability time
PR = the average well flow rate for that particular year

The average production loss per year for a given well is the sum of the losses for all the well components. This concept of lost production is further illustrated in Figure 8.12.

Figure 8.12: Lost/Delayed Production. Consequence of a Well Failure. (TTF =Time To Failure, LCWR= Lost Capacity while Waiting on Rig, T_{RA} = Resource Availability Time, T_{AR} = Active Repair Time)

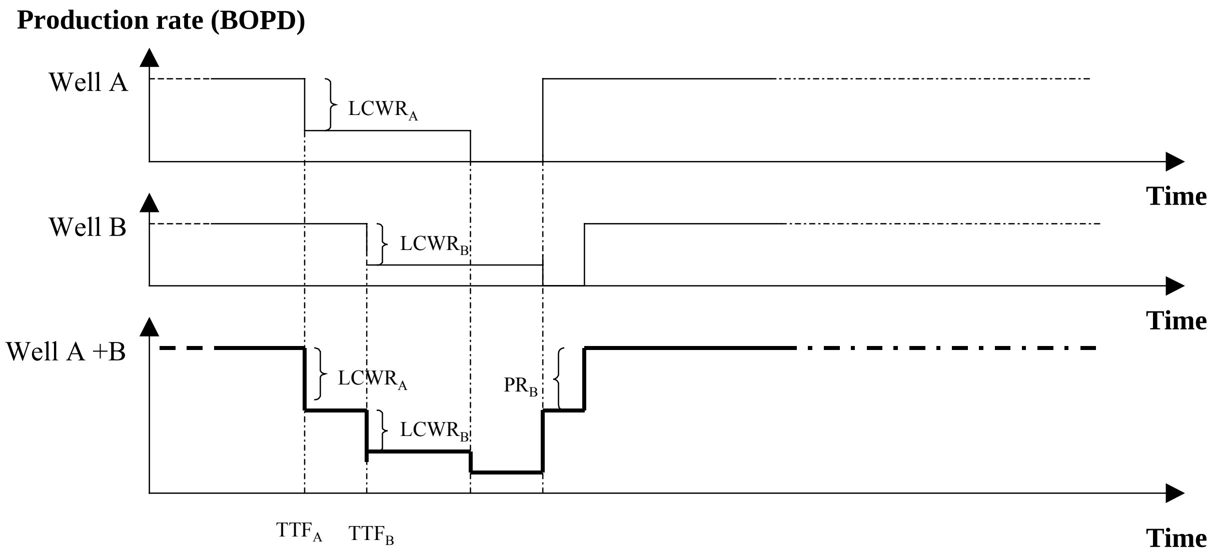


An example is given below:

Example 1:

- Failure: workover required to repair the failure
- Resource: RIG
- Production loss: 50% while waiting on rig (90 days) + 30 days for workover.
- Production rate: 10,000 BOPD in year 3.
- Lost volume: (0.5*90 days + 1*30 days)*10000 BOPD = 750,000BBL

Figure 8.13: Lost/Delayed Production. Consequence of Two Well Failures with Shut-in in Overlapping Time Windows. (TTF_A =Time To Failure for Well A, TTF_B =Time To Failure for Well B, $LCWR_A$ = Lost Capacity while Waiting on Rig for Well A, $LCWR_B$ = Lost Capacity while Waiting on Rig for Well B, PR_B = Production Rate for Well B at the Point Where the Failure Occurred).



If the surface facility capacity, at the time of the failure, is lower than the volume that can be produced by all the wells per time unit, the reduced volume exported from the surface facility per time unit will be less than indicated by the "Well A+B" profile in Figure 8.13. The actual lost/delayed volume depends on the waiting time for repair resources, the active repair times, the total production rate for all the wells, the facility capacity and the production rates for the failed wells.

The financial consequence of a well failure will in addition to the factors discussed above depend on:

- Failure time
- Oil operating margin in year produced ($/bbl)

An example is given below:
Example 2:

- Workover required to repair the failure.
- Resource: RIG.
- Failure time: year 3.
- Production loss: 50% while waiting on rig (90 days) + 30 days for workover.
- Production rate: 10,000 BOPD in year 3.
- Spread cost for RIG: $100,000 per day.
- Oil operating margin in year produced: $10/BBL.
- Discount rate: 15%.
- Financial consequence (FC):

$$FC = \frac{\$100{,}000 / d * 30days}{(1+0.15)^3} + (0.5*90days + 1*30days)*10{,}000BOPD*\frac{\$10 \text{ per BO}}{(1+0.15)^3} \approx 2MM + 4.9MM = 6.9MM$$

8.5.1.1 Mean Time to Repair

The mean time to repair is dependent upon the operation used to repair the system. For each component failure, a repair operation is assumed. Table 8.4 and Table 8.5 display the repair operations and the different repair times for the riser scenarios.

Table 8.4: Repair Times (hrs) for Dry Tree Riser Systems

Operation	TLP						SPAR					
	Dual Casing		Single Casing		Tubing Riser		Dual Casing		Single Casing		Tubing Riser	
Water Depth (ft)	4000	6000	4000	6000	4000	6000	4000	6000	4000	6000	4000	6000
Initial installation – Frac Pack	347	390	287	312	371	410	331	374	275	300	364	404
Initial installation – Horizontal	503	546	443	468	527	566	487	530	431	456	520	560
Workover – Uphole Frac Pack	234	237	234	237	440	488	224	227	224	227	413	460
Workover – Sidetrack, Frac Pack	616	619	616	619	822	870	606	609	606	609	795	842
Workover – Sidetrack, Horizontal	558	561	558	561	764	812	548	551	548	551	737	784
Workover – New Frac Pack	298	301	298	301	504	552	288	291	288	291	477	524
Repair Completion System Leak	136	139	136	139	342	390	126	129	126	129	315	362
Repair / Replace Subsea Tree					182	210					146	174
Repair / Replace Surface Tree	18	18	18	18	18	18	18	18	18	18	18	18
Coil Tubing Operation	24	24	24	24	24	24	24	24	24	24	24	24

Table 8.5: Repair Times (hrs) for Subsea Systems

Operation	Conventional Tree		Horizontal Tree	
Water Depth (ft)	4000	6000	4000	6000
Initial installation – Frac Pack	862	1002	836	961
Initial installation – Horizontal	884	1016	858	975
Workover – Uphole Frac Pack	1010	1198	785	905
Workover – Sidetrack, Frac Pack	1382	1570	1227	1347
Workover – Sidetrack, Horizontal	1315	1514	1019	1131
Workover – New Frac Pack	1146	1334	887	1007
Repair Completion System Leak	784	960	575	683
Repair / Replace Subsea Tree	444	528	960	1144
Coil Tubing Operation	228	270	419	504

The repair times for the 4000 and 6000 foot water depths are used to extrapolate or interpolate the actual repair time for the water depth of the particular scenario.

Table 8.6: Subsea Equipment Repair Times

Subsea Repair Type	% of Wells Affected	Total Time – 4000 feet (hours)	Total Time – 6000 feet (hours)
Repair Pipeline or PLEM	50%	6888	6888
Repair / Replace Flowline Jumper	50%	2822	2922
Repair/ Replace Tree Jumper	One well	2822	2922
Repair / Replace Hydraulic System Umbilical	100%	3830	3930
Repair / Replace Electrical System Umbilical	100%	3830	3930
Repair Extension Pipeline or PLEM only if > 8 wells	50%	6888	6888

Subsea Repair Type	% of Wells Affected	Total Time – 4000 feet (hours)	Total Time – 6000 feet (hours)
Repair / Replace Extension Jumper only if > 8 wells	50%	2822	2822
Repair / Replace Hydraulic Extension Umbilical only if > 8 wells	100%	3830	3930
Repair / Replace Tree Jumper Extension only if > 8 wells	One well	2822	2822
Repair / Replace Electrical Extension Umbilical only if > 8 wells	100%	3830	3930
Repair / Replace Well Jumper	One well	2822	2822
Repair / Replace Well Flying Leads	One well	2256	2280
Repair / Replace Well Control Pod	One well	456	504
Repair / Replace Well Subsea Choke	One well	456	504

8.5.1.2 Vessel Availability

Each operation will have a corresponding repair vessel, depending on the scenario (dry tree, subsea). Table 8.7 displays the repair vessels used in the analysis and the rig availability time for these vessels.

Table 8.7: Availability Times For Subsea Systems

Vessel Type	Vessel Availability Time (days)
Rig (MODU) (8 point spread moored)	120
Pipeline Installation Vessel (DP, heavy lift capability, etc.)	60
Umbilical Installation Vessel	30
MSV Spread (Capability to support lightweight packages)	7
DSV Spread (ROV only – monitor and visual checks)	5
TLP or SPAR Platform Rig	30
Wireline or Coiled Tubing Unit	2

8.5.2 Field Production Rate

A field production profile prediction provides the basis for a field development plan. This field total production rate prediction is the sum of the individual well production rates. Processing facilities capacity typically limits the field production rate during a “plateau” period when many wells are producing at near maximum rates. The production profile will normally represent a “zero equipment failure” scenario and its production volume over the planned lifetime can be regarded as “ideal recoverable reserves”. This “zero equipment failure” scenario is used as an input to the spreadsheet “RAMEX”.

If the processing facility capacity, at the time of a well failure, is lower than the rate that can be produced by the non-failed wells, there is no loss in production rate. This will normally be the case during the plateau period. However, if the processing facility capacity, at the time of the failure, is higher than the rate that can be produced by the non-failed wells, failure will result in a loss of production rate. This will normally be the case in the period before the plateau period (drilling and tie-in of new wells) and the decline phase after the plateau period.

If the total remaining well flow rate exceeds the production capacity by more than the flow rate of the failed well, the production loss is ignored. However, if the flow rate of a particular well is more than the difference between the total well flow rate and the processing facility capacity, the lost production is the difference between the total field flow rate and the particular well flow rate. For calculation purposes, the following algorithm has been used:

$$LP = \begin{cases} 0 & \text{for } (\sum \mathrm{PR}_{\text{remaining}} - PFC) > PR_{lostwell} \\ PR_{lostwell} - (\sum \mathrm{PR}_{\text{remaining}} - PFC) & \text{for } ((\sum \mathrm{PR}_{\text{remaining}} - PFC) > PR_{lostwell} \end{cases}$$

where:

LP = lost production for a field in a particular year (BOPD)

$PR_{lost\ well}$ *= the production rate of a failed well (BOPD)*

$PR_{remaining}$ *= the production rate of the rest of the wells (all minus the failed well) (BOPD)*

PFC = the production flow capacity (BOPD)

8.5.3 Repair Costs

The repair costs is calculated by multiplying the yearly system failure probability by the mean time to repair the failure and the rig spread cost. For each component failure, there may be a different resource associated with the repair, and hence a different cost. The repair cost is calculated by using the following equation:

$$RC_{year} = \frac{P_a(H) - P_a(L)}{1\ \text{year}} * T_{AR} * RSC$$

where:

RC = resource cost associated with a particular failure
T_{AR} *= the mean time to repair a particular component*
RSC = resource spread cost ($/day)

The resource spread cost for the different repair vessels is shown in Table 8.8.

Table 8.8: Spread Costs for Repair Vessels

Rig Type	Rig Spread Cost ($/day)
Rig (MODU) (8 point spread moored)	$240,000
Pipeline Installation Vessel (DP, heavy lift capability, etc.)	$340,000
Umbilical Installation Vessel	$200,000
MSV Spread (Capability to support lightweight packages)	$60,000
DSV Spread (ROV only – monitor and visual checks)	$30,000
TLP or SPAR Platform Rig	$120,000
Wireline or Coiled Tubing Unit	$40,000

Table 8.9: Subsea Equipment Repair Costs

Subsea Repair Type	% of Wells Affected	Repair Cost – 4000 feet ($MM)	Repair Cost – 6000 feet ($MM)
Repair Pipeline or PLEM	50%	5.2	5.2
Repair / Replace Flowline Jumper	50%	1.3	1.5
Repair/ Replace Tree Jumper	One well	1.3	1.5
Repair / Replace Hydraulic System Umbilical	100%	1.3	1.5
Repair / Replace Electrical System Umbilical	100%	1.3	1.5
Repair Extension Pipeline or PLEM only if > 8 wells	50%	5.2	5.2
Repair / Replace Extension Jumper only if > 8 wells	50%	1.3	1.3
Repair / Replace Hydraulic Extension Umbilical only if > 8 wells	100%	1.3	1.5
Repair / Replace Tree Jumper Extension only if > 8 wells	One well	1.3	1.3
Repair / Replace Electrical Extension Umbilical only if > 8 wells	100%	1.3	1.5
Repair / Replace Well Jumper	One well	1.3	1.3
Repair / Replace Well Flying Leads	One well	0.7	0.8
Repair / Replace Well Control Pod	One well	0.3	0.4
Repair / Replace Well Subsea Choke	One well	0.3	0.4

8.6 Results Calculations

8.6.1 RAMEX

The final RAMEX values are calculated by multiplying the yearly failure probability by the sum of the production costs and the repair costs for a particular failure. This is shown in the following equation:

$$RAMEX_{year} = \sum_{\text{component failures}} \frac{P_a(H) - P_a(L)}{1\text{ year}} * \{[(T_{RA} + T_{AR}) * PR * 365] + (T_{AR} * RSC)\}$$

where:

$RAMEX_{year}$ = the total RAMEX of a particular system for a particular year

8.6.2 % Uptime

The % uptime is defined as the percentage of the maximum flow that can be expected during the field's lifetime. This percentage is calculated by dividing the well-days attributed to lost production from the total number of well-days during the field's life.

The calculation for the % uptime of a dry tree system is shown through the following equation:

$$\%\,\text{uptime}_{drytree} = \frac{\sum_{1}^{x} LPD_x}{W_{total} * D_{total}}$$

where:

% uptime$_{drytree}$ = the percentage of maximum flow expected from dry tree wells during the field's lifetime

LPD_x =the days of lost production in a given year (x) for the dry trees calculated through RAMEX techniques

W_x =the number of subsea wells for a given year

D_{total} = the total number of days for a field during it's lifetime

The calculation of the % uptime of a subsea system is shown through the following equation:

$$\%\,\text{uptime}_{subsea} = \frac{\sum_{1}^{x} LPSE_x + \sum_{1}^{x} \frac{LPSW_x}{W_x}}{D_{total}}$$

where:

% uptime$_{subsea}$ = the percentage of maximum flow expected from subsea wells during the field's lifetime

$LPSE_x$ =the days of lost production in a given year (x) for the subsea equipment calculated through RAMEX techniques

$LPSW_x$ =the days of lost production in a given year (x) for the subsea wells calculated through RAMEX techniques

9 LIFECYCLE COST RESULTS

9.1 Introduction

Case studies were run to determine the lifecycle costs of the dry tree and subsea well system alternatives. The cases run are the following:

- Case 1a: The five systems (dual casing, single casing, tubing riser, conventional tree, horizontal tree) for 6 wells and 4000 foot water depth
- Case 1b: The five systems for 6 wells and 6000 foot water depth
- Case 1c: The five systems for 12 wells and 4000 foot water depth
- Case 1d: The five systems for 12 wells and 6000 foot water depth
- Case 2: The two subsea systems (conventional and horizontal tree) varying the number of planned well interventions and unplanned tree interventions (6 wells, 4000 foot water depth)
- Case 2a: Double the number of well interventions (planned and unplanned) and half the number of unplanned tree replacements
- Case 2b: Half the number of well interventions (planned and unplanned) and double the number of unplanned tree replacements

Case 1a and 1b included both dry tree and subsea wells in a single computer calculation. However, a meaningful comparison of these dry tree and subsea alternatives can be made only after all appropriate costs are included. In this case, TLP or Spar platform and facility costs must be added to the dry tree costs before a comparison is valid.

9.2 Inputs

The input data for these case studies are described in Table 9.1.

Table 9.1: Case Study Input Data

	Case 1	Case 2a	Case 2b
Field Life (years)	10	10	10
Zone depth (feet BLM)	10,000	10,000	10,000
Pipeline size (in) - for subsea equipment	12	12	12
Pipeline length (mi) – for subsea equipment	35	35	35
Infield extension (mi) – for subsea equipment	5	5	5
Facilities processing limit (MBOPD)	No limit	No limit	No limit
Oil op. margin in year produced ($/bbl)	8	8	8
Discount rate for NPV calculations (%)	15	15	15
	6 wells 12 wells		
number of frac pack wells	3 6	3	3
number of horizontal wells	3 6	3	3
number of planned uphole frac packs	2 4	4	1
number of planned sidetrack frac packs	2 4	4	1
number of planned sidetrack horizontals	2 5	4	1
number of unplanned tree replacements	2 4	1	3.5
number of unplanned downhole repairs	2.5 5	5	1.5
number of unplanned sand control repairs	5 10	8	3
Limited uncontrolled release cost ($ / BOPD)	$1,700	$1,700	$1,700
Major uncontrolled release cost ($ / BOPD)	$35,000	$35,000	$35,000
Extreme uncontrolled release cost ($ / BOPD)	$250,000	$250,000	$250,000
X-factor	0.8	0.8	0.8
SCSSV location (feet below mudline)	2000	2000	2000
Common cause factor for DC system	0.003	0.003	0.003

The production profiles for the different cases were created by modifying the inputs into the production profile builder. The inputs to the production profile builder and the production profile of Case 1, 2a, and 2b are shown in Table 9.2 through Table 9.5.

Table 9.2: Production Profile Input Data

	Case 1	Case 2a	Case 2b
Start year of wells	0	0	0
Recoverable Reserves per Zone (MM BO)	22	22	20, 22*
Initial production rate (M BOPD)	15	15	10, 15*
Decline rate (% per year)	10	5	15, 10*

* 3 wells were used with one set of reservoir characteristics, 3 wells were used with the other set. This is done to achieve the desired number of planned workovers

Table 9.3: Case 1 Production Profile (MBOPD Average for the Year)

	Year									
Well Number	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
1	13.7	12.9	11.6	10.4	9.4	12.4	13.3	11.9	10.7	9.7
2	13.7	12.9	11.6	10.4	9.4	12.4	13.3	11.9	10.7	9.7
3	13.7	12.9	11.6	10.4	9.4	11.8	13.3	12.0	10.8	9.7
4	13.5	12.9	11.6	10.4	9.4	11.8	13.3	12.0	10.8	9.7
5	13.5	12.9	11.6	10.4	9.4	11.9	13.3	12.0	10.8	9.7
6	13.5	12.9	11.6	10.4	9.4	11.9	13.3	12.0	10.8	9.7

Table 9.4: Case 2a Production Profile (MBOPD Average for the Year)

	Year									
Well Number	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
1	13.3	14.0	13.3	12.6	11.8	14.4	13.7	13.0	12.3	12.8
2	13.3	14.0	13.3	12.6	11.8	14.4	13.7	13.0	12.3	12.8
3	13.3	14.0	13.3	12.6	11.1	14.4	13.7	13.0	12.4	12.1
4	13.2	14.0	13.3	12.6	11.1	14.4	13.7	13.0	12.4	12.1
5	13.2	14.0	13.3	12.6	11.4	14.4	13.7	13.0	12.4	12.4
6	13.2	14.0	13.3	12.6	11.4	14.4	13.7	13.0	12.4	12.4

Table 9.5: Case 2b Production Profile (MBOPD Average for the Year)

	Year									
Well Number	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
1	8.4	8.0	6.8	5.8	4.9	4.2	3.5	3.0	2.6	2.2
2	8.4	8.0	6.8	5.8	4.9	4.2	3.5	3.0	2.6	2.2
3	8.4	8.0	6.8	5.8	4.9	4.2	3.5	3.0	2.6	2.2
4	12.9	12.9	11.7	10.5	9.4	11.1	13.4	12.0	10.8	9.8
5	12.9	13.0	11.7	10.5	9.4	10.5	13.4	12.1	10.9	9.8
6	12.9	13.0	11.7	10.5	9.4	10.8	13.4	12.1	10.9	9.8

9.3 Overall Results

Figure 9.1 through Figure 9.5 present the lifecycle costs (with CAPEX, OPEX, RISKEX, and RAMEX contributions) for case studies with the three dry tree systems and the two subsea systems. Platform and facilities costs must be included with these costs to determine the most economical well system and field development plan.

The Case 1a through 1d examples demonstrate that dry tree wells are more economical than subsea wells beneath or adjacent to a TLP or Spar platforms. In other words, if the same platform and facilities costs are required for each of the alternative well systems, the more expensive and less efficient subsea wells are impractical. However, subsea wells can be located in remote locations beyond the reach of dry tree wells. The methodology and spreadsheet program provides a means to quantify the CAPEX, OPEX, RISKEX and RAMEX factors that determine the differences in these well systems.

Comparison of the three dry tree alternatives demonstrate that:

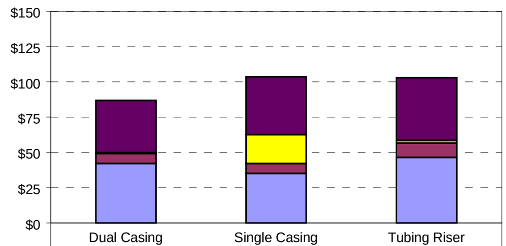
- A single casing riser system is most economical when the RISKEX is minimal, for example, when the wells are in shallow water and when formation pressures are low.
- The OPEX must be significantly reduced to make the tubing riser system to be most economical alternative. For example, a platform likely requires a moonpool to sufficiently improve the tubing riser operational efficiencies.
- A dual casing riser system has higher CAPEX than the single casing or tubing riser systems, especially when the higher tension loads of the dual casing riser system are considered. However, when CAPEX, OPEX, RISKEX and RAMEX are all considered the dual casing riser system is most economical for deepwater developments where reservoirs are abnormally pressured.

The Case 2 subsea well examples shown in Figure 9.5 demonstrate the differences in conventional and horizontal subsea tree systems.

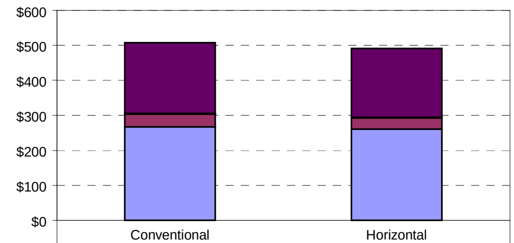
- Horizontal subsea tree system permits workover operations without removing the subsea trees. This system is most economical if numerous workovers are required for recompletions to new zones.

Conventional subsea trees can be replaced more easily than horizontal trees in the event of the failure of a tree valve or actuator. Conventional subsea trees can be replaced without pulling the completions string; horizontal subsea trees require the completion string to be pulled prior to pulling the tree. Therefore, the most economical type of tree is influenced by the reliability of the tree components such as valves, valve actuators, connectors, etc.

Figure 9.1: Completion Alternatives Lifecycle Cost ($MM NPV)– Case 1a, 6 wells, 4000 ft

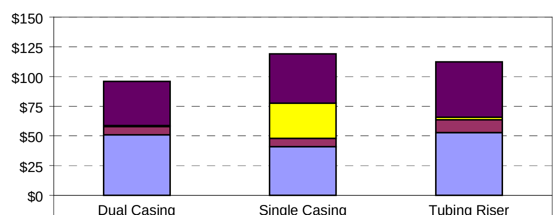


	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	87	104	103
RAMEX ($MM)	37	41	45
RISKEX ($MM)	1	20	2
OPEX ($MM)	7	7	10
CAPEX ($MM)	42	35	47

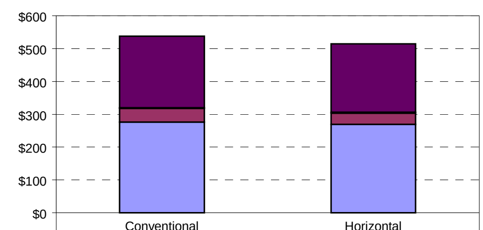


	Conventional	Horizontal
Total Cost ($MM)	507	491
RAMEX ($MM)	202	196
RISKEX ($MM)	3	3
OPEX ($MM)	36	31
CAPEX ($MM)	267	261

Figure 9.2: Completion Alternatives Lifecycle Cost ($MM NPV)– Case 1b, 6 wells, 6000 ft

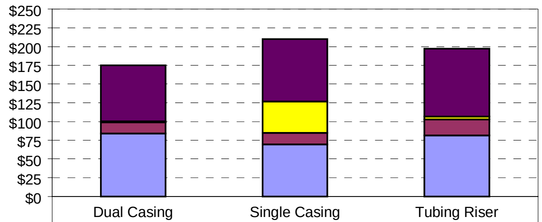


	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	96	119	112
RAMEX ($MM)	37	42	47
RISKEX ($MM)	1	30	2
OPEX ($MM)	7	7	11
CAPEX ($MM)	51	41	53

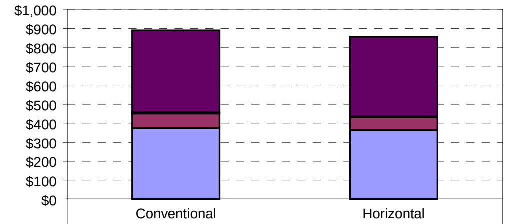


	Conventional	Horizontal
Total Cost ($MM)	538	514
RAMEX ($MM)	218	208
RISKEX ($MM)	3	3
OPEX ($MM)	42	35
CAPEX ($MM)	276	269

Figure 9.3: Completion Alternatives Lifecycle Cost ($MM NPV)– Case 1c, 12 wells, 4000 ft

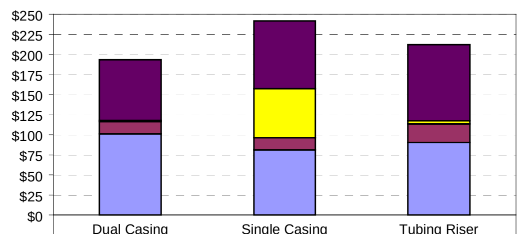


	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	175	210	197
RAMEX ($MM)	75	83	90
RISKEX ($MM)	1	42	4
OPEX ($MM)	15	15	22
CAPEX ($MM)	84	70	81

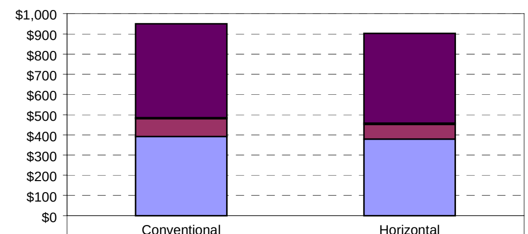


	Conventional	Horizontal
Total Cost ($MM)	889	856
RAMEX ($MM)	432	421
RISKEX ($MM)	5	5
OPEX ($MM)	76	67
CAPEX ($MM)	375	364

Figure 9.4: Completion Alternatives Lifecycle Cost ($MM NPV)- Case 1d, 12 wells, 6000 ft

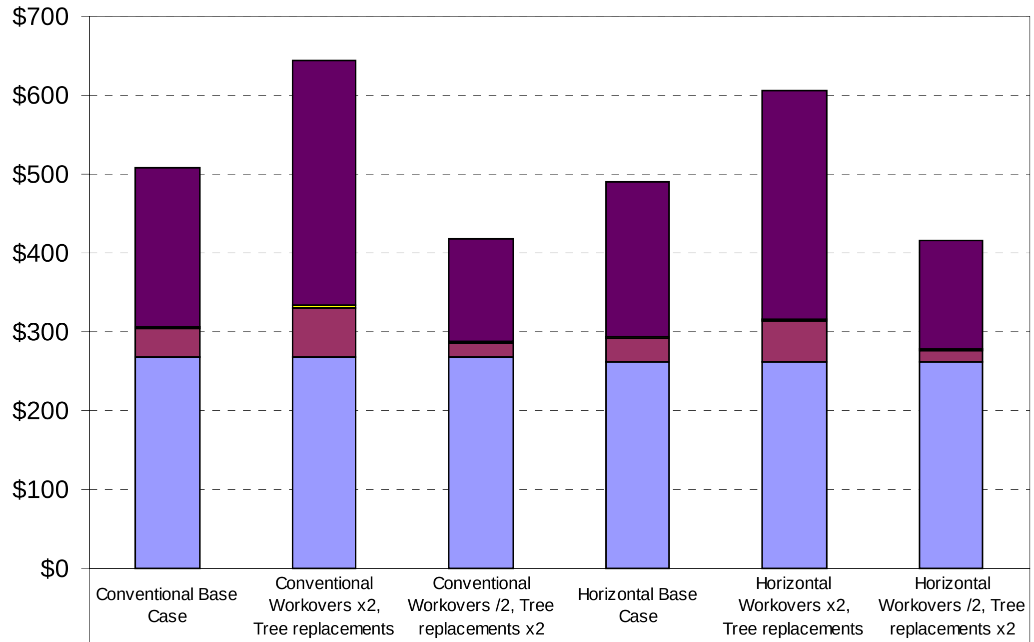


	Dual Casing	Single Casing	Tubing Riser
Total Cost ($MM)	193	242	212
RAMEX ($MM)	76	84	95
RISKEX ($MM)	1	61	4
OPEX ($MM)	15	15	23
CAPEX ($MM)	101	81	91



	Conventional	Horizontal
Total Cost ($MM)	950	903
RAMEX ($MM)	464	445
RISKEX ($MM)	5	5
OPEX ($MM)	88	74
CAPEX ($MM)	393	379

Figure 9.5: Subsea Well Alternative Lifecycle Cost ($MM NPV), Case 2, 6 wells, 4000 feet



	Conventional Base Case	Conventional Workovers x2, Tree replacements	Conventional Workovers /2, Tree replacements x2	Horizontal Base Case	Horizontal Workovers x2, Tree replacements	Horizontal Workovers /2, Tree replacements x2
Total Cost ($MM)	507	643	418	491	607	417
RAMEX ($MM)	202	309	131	196	290	139
RISKEX ($MM)	3	3	2	3	3	2
OPEX ($MM)	36	64	18	31	52	15
CAPEX ($MM)	267	267	267	261	261	261

9.4 RISKEX Results

Table 9.6 and Table 9.7 present the probability of a blowout during normal production (per well-year) and the blowout probabilities for different operations (per operation). Risks of a blowout for each operation depends on the number of steps in the operational procedure, and for each step: the number barriers, reliability of the well system components comprising the barriers and duration of the step. The total RISKEX for a field development depends on the number and types of operations that are performed during the field life.

Table 9.6: Uncontrolled Release Probability (x 10^{-4}) – Case 1a and 1c, 4000ft

	Units	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
Production	per well-year	0.4	3.6	1.3	1.9	1.8
Initial installation – Frac Pack	per operation	1.0	9.4	2.5	2.8	2.3
Initial installation – Horizontal	per operation	1.1	11	4.0	2.9	2.4
Workover – Uphole Frac Pack	per operation	4.7	36	11	5.0	4.5
Workover – Sidetrack, Frac Pack	per operation	5.0	40	12	5.3	4.6
Workover – Sidetrack, Horizontal	per operation	5.0	39	13	5.2	4.7
Workover - New Frac Pack	per operation	4.0	29	6.3	3.1	2.5
Repair Completion System Leak	per operation	3.8	27	5.1	2.8	1.3
Coil Tubing Downhole Operation	per operation	N.A.	N.A.	N.A.	<0.01	0.8
Repair / Replace Subsea Tree	per operation	N.A.	N.A.	N.A.	0.45	3.6

Table 9.7: Lifetime Uncontrolled Release Probability (x 10^{-4}) – Case 1b and 1d, 6000ft

	Units	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
Production	per well-year	0.4	5	1.3	1.9	1.8
Initial installation – Frac Pack	per operation	1.0	13	3.1	2.9	2.3
Initial installation – Horizontal	per operation	1.2	16	4.9	3.0	2.4
Workover – Uphole Frac Pack	per operation	4.9	51	13	5.1	4.5
Workover – Sidetrack, Frac Pack	per operation	5.2	56	15	5.4	4.6
Workover – Sidetrack, Horizontal	per operation	5.1	54	16	5.3	4.7
Workover - New Frac Pack	per operation	4.1	40	7.6	3.1	2.5
Repair Completion System Leak	per operation	4.0	38	6.2	2.8	1.3
Repair Coil Tubing Downhole	per operation	N.A.	N.A.	N.A.	<0.01	0.8
Repair / Replace Subsea Tree	per operation	N.A.	N.A.	N.A.	0.47	3.6

9.5 Calibration of the System Model

The model has been calibrated against historical data from conventional land and offshore wells by calculating RISKEX with a "zero" riser length (water depth). The results shown in Table 9.8 were produced for the Dual Casing Riser System, Conventional Tree System, and Horizontal Tree System calculated for "zero" riser length.

Table 9.8: RISKEX Comparison of Dual Casing System to a Conventional Platform Well

Operation	Units	Probability of an Uncontrolled Leak to the Environment (x 10^{-4})			
		Historical Figures	Dual Casing System*	Conventional Subsea Tree	Horizontal Subsea Tree
Production	Per well year	0.9	0.4	1.9	1.8
Workover	per operation	5.8	4.7	5.2	4.6
Installation	Per operation	5.2	1.0	2.8	2.3

*Note: Zero riser length Workover RISKEX is an average of Uphole Frac Pack, Sidetrack Frac Pack and Sidetrack Horizontal operations.

The spreadsheet program calculates the blowout frequency from a (zero length) Dual or Single Casing Riser is about half the historical frequency for production operations, one fifth of the historical frequency for installation operations, and very close to the historical frequency for workover operations.

For the subsea system, the spreadsheet program estimates the frequency of a blowout from the conventional and horizontal trees to be about twice that of the historical frequency for production operations, about the same as the historical frequency for workover operations and roughly half the historical frequency for installation operations.

These results demonstrate that the methodology and spreadsheet tool calculations provide reliability results that are close to historical performance. This methodology provides a quantitative procedure to select the most cost effective completion system for site specific conditions.

9.6 RAMEX Results

Subsea wells can be located at locations that are remote to a drilling or production facility whereas dry tree wells require an expensive platform. However, subsea wells generally experience lower operating efficiency "Uptime," and repair costs and lost production greater than dry tree well systems. Table 9.9 shows a typical RAMEX case example where the dry tree wells have about 98% uptime as compared to about 90% uptime for subsea wells. Repair costs for the dry tree wells is in the range of 12 to 15 million dollars as compared to 65 to 69 million dollars for subsea wells. The production lost cost is 25 to 30 million for the dry tree wells as compared to about 132 million for the subsea wells. Similar results are shown in the other figures.

Table 9.9: Completion Alternatives RAMEX Results – Case 1a, 6 wells, 4000 ft

	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
% Uptime	98.0 %	97.8 %	97.8 %	89.6 %	89.6 %
Repair Cost ($MM)	11.4	12.0	15.7	69.4	64.1
Production Lost Cost ($MM)	25.6	29.1	28.9	132.3	131.9
Total RAMEX ($MM)	**37.0**	**41.1**	**44.6**	**201.7**	**196.0**

Table 9.10: Completion Alternatives RAMEX Results – Case 1b, 6 wells, 6000 ft

	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
% Uptime	98.0 %	97.8 %	97.7 %	89.1 %	89.3 %
Repair Cost ($MM)	11.5	12.1	16.8	80.7	72.6
Production Lost Cost ($MM)	25.7	29.5	29.9	136.8	135.5
Total RAMEX ($MM)	**37.2**	**41.6**	**46.7**	**217.5**	**208.1**

Table 9.11: Completion Alternatives RAMEX Results – Case 1c, 12 wells, 4000 ft

	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
% Uptime	98.0 %	97.8 %	97.8 %	88.5 %	88.5 %
Repair Cost ($MM)	22.9	24.0	31.5	139.2	128.3
Production Lost Cost ($MM)	52.1	59.2	58.9	293.0	292.3
Total RAMEX ($MM)	**75.0**	**83.2**	**90.4**	**432.2**	**420.6**

Table 9.12: Completion Alternatives RAMEX Results – Case 1d, 12 wells, 6000 ft

	Dual Casing	Single Casing	Tubing Riser	Conventional	Horizontal
% Uptime	98.0 %	97.7 %	97.7 %	88.0 %	88.2 %
Repair Cost ($MM)	23.0	24.4	33.7	162.0	145.6
Production Lost Cost ($MM)	52.5	59.9	60.8	302.1	299.6
Total RAMEX ($MM)	**75.5**	**84.3**	**94.5**	**464.1**	**445.2**

Table 9.13: RAMEX Results – Case 2, Subsea Well Alternatives, 6 wells, 4000 feet

	Conventional Tree – Base Case	Horizontal Tree – Base Case	Conv. Tree – Case 2a	Hor. Tree – Case 2a	Conv. Tree – Case 2b	Hor. Tree – Case 2b
% Uptime	89.6 %	89.6 %	85.3 %	85.6 %	91.7 %	91.3 %
Repair Cost ($MM)	69.4	64.1	107.7	92.0	46.9	52.6
Production Lost Cost ($MM)	132.3	131.9	201.7	198.2	84.1	86.2
Total RAMEX ($MM)	**201.7**	**196.0**	**309.4**	**290.2**	**131.0**	**138.8**

APPENDIX I

FMEA WORKSHEETS